UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 2003

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ____________ to ____________

Commission file number 1-4174

THE WILLIAMS COMPANIES, INC.
(Exact name of registrant as specified in its charter)

DELAWARE	73-0569878
(State of Incorporation)	(IRS Employer Identification Number)
ONE WILLIAMS CENTER TULSA, OKLAHOMA	74172
(Address of principal executive office)	(Zip Code)

Registrant's telephone number: (918) 573-2000

NO CHANGE
Former name, former address and former fiscal year, if changed since last report.

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes X No

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes X No

Indicate the number of shares outstanding of each of the issuer's classes of common stock as of the latest practicable date.

Class	Outstanding at October 31, 2003
Common Stock, $1 par value	518,183,708 Shares

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Certain matters discussed in this report, excluding historical information, include forward-looking statements - statements that discuss Williams' expected future results based on current and pending business operations. Williams makes these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995.

Forward-looking statements can be identified by words such as "anticipates," "believes," "expects," "planned," "scheduled," "could," "continues," "estimates," "forecasts," "might," "potential," "projects" or similar expressions. Although Williams believes these forward-looking statements are based on reasonable assumptions, statements made regarding future results are subject to a number of assumptions, uncertainties and risks that may cause future results to be materially different from the results stated or implied in this document. Additional information about issues that could cause actual results to differ materially from forward-looking statements is contained in The Williams Companies, Inc.'s 2002 Form 10-K.

The Williams Companies, Inc.
Consolidated Statement of Operations
(Unaudited)

(Dollars in millions, except per-share amounts)	Three months ended September 30, 2003	Three months ended September 30, 2002*	Nine months ended September 30, 2003	Nine months ended September 30, 2002*
Revenues:				
Power	$ 3,888.4	$ (219.2)	$ 10,610.1	$ (73.9)
Gas Pipeline	316.6	324.0	951.9	919.5
Exploration & Production	168.7	209.4	612.8	652.2
Midstream Gas & Liquids	841.0	405.5	2,485.6	1,096.4
Other	11.0	26.0	59.1	78.7
Intercompany eliminations	(430.4)	(26.5)	(1,434.6)	(78.4)
Total revenues	4,795.3	719.2	13,284.9	2,594.5
Segment costs and expenses:				
Costs and operating expenses	4,434.7	527.3	11,973.1	1,594.4
Selling, general and administrative expenses	97.3	158.1	321.6	452.7
Other				

(income)
expense - net
(24.8)
(109.8)
(249.3) 37.1
----------- -
---------- --
--------- ---

Total segment
costs and
expenses
4,507.2 575.6
12,045.4
2,084.2 -----
------ ------
----- -------
---- --------
--- General
corporate
expenses 17.8
44.1 62.5
116.4 -------
---- --------
--- ---------
-- ----------
- Operating
income
(loss): Power
21.7 (316.6)
255.9 (458.1)
Gas Pipeline
135.4 138.3
396.6 355.2
Exploration &
Production
56.3 226.7
344.2 425.0
Midstream Gas
& Liquids
70.0 104.3
245.5 197.7
Other 4.7
(9.1) (2.7)
(9.5) General
corporate
expenses
(17.8) (44.1)
(62.5)
(116.4) -----
------ ------
----- -------
---- --------
--- Total
operating
income 270.3
99.5 1,177.0
393.9
Interest
accrued
(276.3)
(341.5)
(1,035.1)
(799.2)
Interest
capitalized
11.4 7.2 34.6
18.3 Interest
rate swap
income (loss)
2.5 (52.2)
(6.4) (125.2)
Investing
income (loss)
40.6 55.3
43.8 (122.9)
Minority
interest in
income and
preferred
returns of

consolidated
subsidiaries
(5.6) (12.2)
(15.1) (35.7)
Other income
- net 3.7 .5
39.7 19.0 ---
-------- ----
------- -----
------ ------
----- Income
(loss) from
continuing
operations
before income
taxes and
cumulative
effect of
change in
accounting
principles
46.6 (243.4)
238.5 (651.8)
Provision
(benefit) for
income taxes
23.8 (72.2)
138.8 (191.3)
----------- -
---------- --
--------- ---

Income (loss)
from
continuing
operations
22.8 (171.2)
99.7 (460.5)
Income (loss)
from
discontinued
operations
83.5 (122.9)
223.1 (75.0)
----------- -
---------- --
--------- ---

Income (loss)
before
cumulative
effect of
change in
accounting
principles
106.3 (294.1)
322.8 (535.5)
Cumulative
effect of
change in
accounting
principles --
-- (761.3) --
----------- -
---------- --
--------- ---
-------- Net
income (loss)
106.3 (294.1)
(438.5)
(535.5)
Preferred
stock
dividends --
6.8 29.5 83.3
----------- -
---------- --
--------- ---

Income (loss)
applicable to

common stock
$ 106.3 $
(300.9) $
(468.0) $
(618.8)
===========
===========
===========
===========
Basic
earnings
(loss) per
common share:
Income (loss)
from
continuing
operations $
.05 $ (.34) $
.14 $ (1.05)
Income (loss)
from
discontinued
operations
.16 (.24) .43
(.15) -------
---- --------
--- ---------
-- ----------
- Income
(loss) before
cumulative
effect of
change in
accounting
principles
.21 (.58) .57
(1.20)
Cumulative
effect of
change in
accounting
principles --
-- (1.47) --
----------- -
---------- --
--------- ---
-------- Net
income (loss)
$ .21 $ (.58)
$ (.90) $
(1.20)
===========
===========
===========
===========
Weighted-
average
shares
(thousands)
518,292
516,901
518,014
516,688
Diluted
earnings
(loss) per
common share:
Income (loss)
from
continuing
operations $
.04 $ (.34) $
.13 $ (1.05)
Income (loss)
from
discontinued
operations
.16 (.24) .43
(.15) -------
---- --------
--- ---------

-- ----------
- Income
(loss) before
cumulative
effect of
change in
accounting
principles
.20 (.58) .56
(1.20)
Cumulative
effect of
change in
accounting
principles --
-- (1.45) --
----------- -
---------- --
--------- ---
-------- Net
income (loss)
$ .20 $ (.58)
$ (.89) $
(1.20)
===========
===========
===========
===========
Weighted-
average
shares
(thousands)
524,711
516,901
523,938
516,688 Cash
dividends per
common share
$ .01 $ .01 $
.03 $ .41

* Certain amounts have been reclassified as described in Note 2 of Notes to Consolidated Financial Statements.

See accompanying notes.

The Williams Companies, Inc.
Consolidated Balance Sheet
(Unaudited)

(Dollars in millions, except per-share amounts)	September 30, 2003	December 31, 2002*
ASSETS		
Current assets:		
Cash and cash equivalents	$ 3,428.0	$ 1,650.4
Restricted cash	19.4	102.8
Restricted investments	155.1	--
Accounts and notes receivable less allowance of $116.8 ($111.8 in 2002)	1,691.4	2,415.4
Inventories	270.0	368.1
Energy risk management and trading assets	--	296.7
Derivative assets	3,930.2	5,024.3
Margin deposits	427.9	804.8
Assets of discontinued operations	429.4	1,263.6
Deferred income taxes	706.7	569.2
Other current assets and deferred charges	271.9	390.8
Total current assets	11,330.0	12,886.1
Restricted cash	197.3	188.1
Restricted		

investments
288.6 --
Investments
1,389.0
1,468.6
Property,
plant and
equipment,
at cost
16,048.3
15,689.7
Less
accumulated
depreciation
and
depletion
(3,923.0)
(3,663.7) --
---------- -

12,125.3
12,026.0
Energy risk
management
and trading
assets --
1,821.6
Derivative
assets
3,168.7
1,865.1
Goodwill
1,059.5
1,059.5
Assets of
discontinued
operations -
- 2,941.1
Other assets
and deferred
charges
743.3 732.4

Total assets
$ 30,301.7 $
34,988.5
============
============
LIABILITIES
AND
STOCKHOLDERS'
EQUITY
Current
liabilities:
Notes
payable $
6.6 $ 934.8
Accounts
payable
1,397.9
1,939.8
Accrued
liabilities
914.4
1,406.4
Liabilities
of
discontinued
operations
86.6 532.1
Energy risk
management
and trading
liabilities
-- 244.4
Derivative
liabilities
3,765.9
5,168.3
Long-term

debt due
within one
year 1,913.3
1,082.7 ----
-------- ---

Total
current
liabilities
8,084.7
11,308.5
Long-term
debt
10,990.1
11,076.7
Deferred
income taxes
3,127.2
3,353.6
Liabilities
and minority
interests of
discontinued
operations -
- 1,258.0
Energy risk
management
and trading
liabilities
-- 680.9
Derivative
liabilities
2,788.7
1,209.8
Other
liabilities
and deferred
income
1,017.0
968.3
Contingent
liabilities
and
commitments
(Note 11)
Minority
interests in
consolidated
subsidiaries
98.6 83.7
Stockholders'
equity:
Preferred
stock, $1
per share
par value,
30 million
shares
authorized,
1.5 million
issued in
2002 --
271.3 Common
stock, $1
per share
par value,
960 million
shares
authorized,
521.2
million
issued in
2003, 519.9
million
issued in
2002 521.2
519.9
Capital in
excess of
par value
5,192.8

5,177.2 Accumulated deficit (1,367.8) (884.3) Accumulated other comprehensive income (loss) (84.1) 33.8 Other (28.1) (30.3) ------------ ------------ 4,234.0 5,087.6 Less treasury stock (at cost), 3.2 million shares of common stock in 2003 and 2002 (38.6) (38.6) ------------ ------------ Total stockholders' equity 4,195.4 5,049.0 ------------ ------------ Total liabilities and stockholders' equity $ 30,301.7 $ 34,988.5 ============ ============

* Certain amounts have been reclassified as described in Note 2 of Notes to Consolidated Financial Statements.

See accompanying notes.

The Williams Companies, Inc.
Consolidated Statement of Cash Flows
(Unaudited)

(Millions) Nine months ended September 30, ------------------------------------- 2003 2002* ------------- ------------ -- OPERATING ACTIVITIES: Income (loss) from continuing operations $ 99.7 $ (460.5) Adjustments to reconcile to cash provided (used) by operations: Depreciation, depletion and amortization 504.3 482.5 Provision (benefit) for deferred income taxes 126.0 (148.1) Payments of guarantees and payment obligations related to WilTel -- (753.9) Provision for loss on investments, property and other assets 133.5 136.9 Net gain on disposition of assets (125.5) (202.5) Provision for uncollectible accounts: WilTel -- 269.9 Other 6.6 15.7 Minority interest in income and preferred returns of consolidated subsidiaries 15.1 35.7 Amortization and taxes associated with stock-based awards 16.4 24.5 Payment of deferred set-up fee and fixed rate interest on RMT note payable (265.0) -- Accrual for fixed rate interest included in the RMT note payable 99.3 21.0 Amortization of deferred set-up fee and fixed rate interest on RMT note payable 154.5 43.5 Cash provided (used) by changes in current assets and liabilities: Restricted cash 1.0 (118.6) Accounts and notes receivable 687.6 (473.0) Inventories 56.8 (67.0) Margin deposits 376.9 (485.4) Other current assets and

deferred charges
(28.6) (371.1)
Accounts payable
(522.6) (29.8)
Accrued liabilities
(443.2) (18.3)
Changes in current
and noncurrent
derivative and
energy risk
management and
trading assets and
liabilities (306.3)
609.9 Changes in
noncurrent
restricted cash
(2.4) (103.6) Other,
including changes in
noncurrent assets
and liabilities
(67.0) (64.1) ------
------ ------------
Net cash provided
(used) by operating
activities of
continuing
operations 517.1
(1,656.3) Net cash
provided by
operating activities
of discontinued
operations 177.7
277.4 ------------ -
----------- Net cash
provided (used) by
operating activities
694.8 (1,378.9) ----
-------- -----------
- FINANCING
ACTIVITIES: Proceeds
from notes payable -
- 908.0 Payments of
notes payable
(896.0) (2,014.0)
Proceeds from long-
term debt 1,776.5
3,481.1 Payments of
long-term debt
(1,033.6) (1,929.5)
Proceeds from
issuance of common
stock .4 3.2
Dividends paid
(48.1) (218.8)
Proceeds from
issuance of
preferred stock --
271.3 Repurchase of
preferred stock
(275.0) (135.0)
Payments of debt
issuance costs
(56.8) (179.8)
Payments/dividends
to minority and
preferred interests
(1.1) (42.9) Changes
in restricted cash
75.5 (203.8) Changes
in cash overdrafts
(46.7) 40.6 Other--
net .1 (23.9) ------
------ ------------
Net cash used by
financing activities
of continuing
operations (504.8)
(43.5) Net cash
provided (used) by
financing activities
of discontinued

operations (92.6) 586.0 ------------ ------------ Net cash provided (used) by financing activities (597.4) 542.5 ------------ ------------ INVESTING ACTIVITIES: Property, plant and equipment: Capital expenditures (734.2) (1,214.5) Proceeds from dispositions 522.7 449.1 Purchases of investments/advances to affiliates (20.6) (283.3) Purchases of restricted investments (597.9) -- Proceeds from sales of businesses 2,204.5 1,920.2 Proceeds from sale of restricted investments 150.0 -- Proceeds from dispositions of investments and other assets 81.4 98.1 Proceeds received on advances to affiliates -- 75.0 Other--net 15.3 50.3 ------------ ------------ Net cash provided by investing activities of continuing operations 1,621.2 1,094.9 Net cash used by investing activities of discontinued operations (23.7) (266.9) ------------ ------------ Net cash provided by investing activities 1,597.5 828.0 ------------ ------------ Increase (decrease) in cash and cash equivalents 1,694.9 (8.4) Cash and cash equivalents at beginning of period** 1,736.0 1,301.1 ------------ ------------ Cash and cash equivalents at end of period** $ 3,430.9 $ 1,292.7 ============ ============

* Amounts have been restated or reclassified as described in Note 2 of Notes to Consolidated Financial Statements.

** Includes cash and cash equivalents of discontinued operations of $2.9 million, $85.6 million, $60.6 million and $60.7 million at September 30, 2003, December 31, 2002, September 30, 2002 and December 31, 2001, respectively.

See accompanying notes.

The Williams Companies, Inc.
Notes to Consolidated Financial Statements
(Unaudited)

1. General

Company outlook

As discussed in The Williams Companies, Inc.'s (Williams or the Company) Form 10-K for the year ended December 31, 2002, events in 2002 and the last half of 2001 significantly impacted the Company's operations, both past and future. On February 20, 2003, Williams outlined its planned business strategy for the next several years which management believes to be a comprehensive response to the events which impacted the energy sector and Williams during 2002. The plan focuses on retaining a strong, but smaller, portfolio of natural gas businesses and bolstering Williams' liquidity through additional asset sales, strategic levels of financing at the Williams and subsidiary levels and additional reductions in its operating costs. The plan is designed to provide Williams with a clear strategy to address near-term and medium-term liquidity issues and further de-leverage the company with the objective of returning to investment grade status and developing a balance sheet capable of supporting retained businesses with favorable returns and opportunities for growth. As part of this plan, Williams expects to generate proceeds, net of related debt, of approximately $4 billion during 2003 and 2004, primarily from asset sales as well as the contribution of proceeds from the sale and/or termination of certain contracts within its marketing and trading portfolio. Through September 30, 2003, Williams received approximately $3.1 billion in net proceeds from the sale of assets and businesses and the sale and/or termination of certain marketing and trading contracts. Of this amount, $2.8 billion was realized from the sale of assets and businesses, including the following:

- the retail travel centers;
- the Midsouth refinery;
- Texas Gas Transmission Corporation;
- Williams' general partnership interest and limited partner investment in Williams Energy Partners;
- certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at a plant in Redwater, Alberta;
- Williams' interest in Williams Bio-Energy L.L.C.;
- certain natural gas exploration and production properties in Kansas, Colorado, Utah and New Mexico; and
- Williams' investment in soda ash operations in Colorado.

As previously announced, the Company intends to reduce its commitment to the activities of Williams Power Company (Power) (formerly named Williams Energy Marketing & Trading Company). This reduction may be realized by entering into a joint venture with a third party or through the sale of a portion of or all of the marketing and trading portfolio. Through the nine month period ended September 30, 2003, Power has sold or entered into agreements to terminate certain contracts for cash proceeds totaling approximately $315 million, which is included in the $3.1 billion total noted above.

During second-quarter 2003, Williams issued $300 million of 5.5 percent junior subordinated convertible debentures due 2033 and $800 million of 8.625 percent notes due 2010, and a Williams subsidiary received proceeds from a $500 million term loan due 2007. Portions of the proceeds from these debt issues, borrowings and asset sales were used to redeem $275 million of preferred stock, the Williams Production RMT Company (RMT) note payable (including deferred fees and interest) (see Note 10) and $888 million of other long-term debt that matured or required payments from the proceeds of asset sales.

As of September 30, 2003, the Company has notes payable and long-term debt maturing through first-quarter 2004 totaling approximately $1.6 billion, consisting largely of $1.4 billion of Williams' senior unsecured 9.25 percent notes. In the third quarter of 2003, Williams' Board of Directors authorized the Company to retire or otherwise prepay up to $1.8 billion of debt, including $1.4 billion designated for the Company's 9.25 percent notes due March 15, 2004. On October 8, 2003, the Company announced a cash tender offer for any and all of these $1.4 billion notes as well as cash tender offers and consent solicitations for approximately $241 million of additional outstanding notes and debentures. The Company will use available cash to fund the purchase of any notes accepted under the tender offers. As of October 31, 2003, approximately $720 million of the 9.25 percent notes had been accepted for purchase. Additionally, Williams received tenders of notes and deliveries of related consents from holders of approximately $230 million of the other notes. The tender offers are scheduled to expire on November 6, 2003. The Company anticipates that cash on hand, proceeds from additional asset sales and cash flows from retained businesses will enable the Company to meet its liquidity needs.

Other

The accompanying interim consolidated financial statements of Williams do not include all notes in annual financial statements and therefore should be read in conjunction with the consolidated financial statements and notes thereto in Williams' Annual Report on Form 10-K. The accompanying unaudited financial statements include all normal recurring adjustments and others, including asset impairments, loss accruals, and the change in accounting principles which, in the opinion of Williams' management, are necessary to present fairly its financial position at September 30, 2003, its results of operations for the three and nine months ended September 30, 2003 and 2002 and cash flows for the nine months ended September 30, 2003 and 2002.

During the second quarter of 2003, Power corrected the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001. As a result, Power recognized $80.7 million of revenue in the second-quarter of 2003 attributable to prior periods. Approximately $46.6 million of this revenue relates to a correction of net energy trading assets for certain derivative contract terminations occurring in 2001. The remaining $34.1 million relates to net gains on certain other derivative contracts entered into in 2002 and 2001 that the Company now believes should not have been deferred as a component of other comprehensive income due to the incorrect designation of these contracts as cash flow hedges. Management, after consultation with its independent auditor, concluded that the effect of the previous accounting treatment was not material to prior periods, expected 2003 results and trend of earnings.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make estimates and assumptions that affect the amounts reported in the consolidated financial statements and accompanying notes. Actual results could differ from those estimates.

2. Basis of presentation
- --

During third-quarter 2003, Williams announced the name change of Williams Energy Marketing and Trading to Power. Williams' management believes the new name more accurately reflects the emphasis of the segment's current business activity.

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standards (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the accompanying consolidated financial statements and notes reflect the results of operations, financial position and cash flows of the following components as discontinued operations (see Note 6):

o Kern River Gas Transmission (Kern River), previously one of Gas Pipeline's segments;

o two natural gas liquids pipeline systems, Mid-American Pipeline and Seminole Pipeline, previously part of the Midstream Gas & Liquids segment;

o the Colorado soda ash mining operations, part of the previously reported International segment;

o Central natural gas pipeline, previously one of Gas Pipeline's segments;

o retail travel centers concentrated in the Midsouth, part of the previously reported Petroleum Services segment;

o refining and marketing operations in the Midsouth, including the Midsouth refinery, part of the previously reported Petroleum Services segment;

o bio-energy operations, part of the previously reported Petroleum Services segment;

o Texas Gas Transmission Corporation, previously one of Gas Pipeline's segments;

o Williams' general partnership interest and limited partner investment in Williams Energy Partners, previously the Williams Energy Partners segment;

- o refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment;

- o Gulf Liquids New River Project LLC, previously part of the Midstream Gas & Liquids segment;

- o natural gas properties in the Hugoton and Raton basins, previously part of the Exploration & Production segment; and

- o certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at a plant in Redwater, Alberta, previously part of the Midstream Gas & Liquids segment.

Unless indicated otherwise, the information in the Notes to the Consolidated Financial Statements relates to the continuing operations of Williams. Williams expects that other components of its business may be classified as discontinued operations in the future as those operations are sold or classified as held-for-sale.

Certain other statement of operations, balance sheet and cash flow amounts have been reclassified to conform to the current classifications.

3. Changes in accounting policies and cumulative effect of change in accounting principles

Energy commodity risk management and trading activities and revenues

Effective January 1, 2003, Williams adopted Emerging Issues Task Force (EITF) Issue No. 02-3, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3). The Issue rescinded EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." EITF 02-3 precludes fair value accounting for commodity trading inventories, and for energy trading contracts that are not derivatives pursuant to SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." As a result of initial application of this Issue in first-quarter 2003, Williams reduced energy risk management and trading assets (including inventories) by $2,159.2 million, energy risk management and trading liabilities by $925.3 million and net income by $762.5 million (net of a $471.4 million benefit for income taxes). Approximately $755 million of the reduction in net income relates to Power, with the remainder relating to Midstream Gas & Liquids. The reduction of net income is reported as a cumulative effect of a change in accounting principle. The change resulted primarily from power tolling, load serving, transportation and storage contracts not meeting the definition of a derivative and no longer being reported at fair value.

The power tolling, load serving, transportation and storage contracts are now accounted for on an accrual basis. Under this model, revenues for sales of products are recognized in the period of delivery. Revenues and costs associated with these non-derivative energy contracts, other non-derivative activities and physically settled derivative contracts are each reflected gross in revenues and costs and operating expenses in the Consolidated Statement of Operations beginning January 1, 2003. This change significantly impacts the presentation of revenues and costs and operating expenses. Derivative energy contracts are reflected at fair value, and gains and losses due to changes in fair value of derivatives not designated as hedges under SFAS No. 133 are reflected net in revenues. Physical commodity inventories previously reflected at fair value are now stated at average cost, not in excess of market. Inventory acquisition costs, and the related costs and operating expenses in the Consolidated Statement of Operations for storable commodities physically settled under derivative contracts, reflect market prices on the date of physical settlement. Derivative energy contracts are classified in the Consolidated Balance Sheet as current and noncurrent assets and current and noncurrent liabilities based on the timing of expected future cash flows used in determining fair value of individual contracts. In addition, derivative assets and liabilities on the Consolidated Balance Sheet include a $469 million net asset representing the remaining fair value of certain derivative contracts for which Power elected the normal purchases and sales exclusion during second-quarter 2003 in accordance with SFAS No. 133. Through September 30, 2003, $10 million of the initial fair value of these contracts has been recognized in earnings. The remaining balance will be recognized in earnings over the remaining periods of the contracts' terms based on the estimated cash flows of the contracts at the time of election. As of September 30 2003, the remaining terms of contracts for which the normal purchases and sales exclusion has been elected range from approximately four to seven years.

Asset retirement obligations

Effective January 1, 2003, Williams adopted SFAS No. 143, "Accounting for Asset Retirement Obligations." This Statement requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made, and that the associated asset retirement costs be capitalized as part of the carrying amount of the long-lived asset. The Statement also amends SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." As required by the new standard, Williams recorded liabilities equal to the present value of expected future asset retirement obligations at January 1, 2003. The obligations relate to producing wells, offshore platforms, underground storage caverns and gas gathering well connections. At the end of the useful life of each respective asset, Williams is legally obligated to plug both producing wells and storage caverns and remove any related surface equipment, to dismantle offshore platforms, and to cap certain gathering pipelines at the wellhead connection and remove any related surface equipment. The liabilities are partially offset by increases in property, plant and equipment, net of accumulated depreciation, recorded as if the provisions of the Statement had been in effect at the date the obligation was incurred. As a result of the adoption of SFAS No. 143, Williams recorded a long-term liability of $33.4

million; property, plant and equipment, net of accumulated depreciation, of $24.8 million and a credit to earnings of $1.2 million (net of a $.1 million benefit for income taxes) reflected as a cumulative effect of a change in accounting principle. Williams also recorded a $9.7 million regulatory asset for retirement costs of dismantling offshore platforms expected to be recovered through regulated rates. In connection with adoption of SFAS No. 143, Williams changed its method of accounting to include salvage value of equipment related to producing wells in the calculation of depreciation. The impact of this change is included in the amounts discussed above. Williams has not recorded liabilities for pipeline transmission assets, processing and refining assets, and gas gathering systems pipelines. A reasonable estimate of the fair value of the retirement obligations for these assets cannot be made as the remaining life of these assets is not currently determinable. If the Statement had been adopted at the beginning of 2002, the impact to Williams' income from continuing operations and net income would have been immaterial. There would have been no impact on earnings per share.

4. Asset sales, impairments and other items

Williams evaluates its investments for impairment when events or changes in circumstances indicate, in management's judgment, that the carrying value of such assets may have experienced an other-than-temporary decline in value. When evidence of loss in value has occurred, management's estimate of fair value of the investment is compared to the carrying value of the investment to determine whether an impairment has occurred. If the estimated fair value is less than the carrying cost and the decline in value is considered other than temporary, the excess of the carrying cost over the fair value is recognized in the financial statements as an impairment.

Judgments and assumptions are inherent in management's assessment of whether there has been any evidence of a loss in value that warrants an estimation of fair value. Judgments and assumptions are also inherent in management's estimate of an investment's fair value used to determine whether a loss in value has occurred and to measure the amount of impairment to recognize. In addition, judgements and assumptions are involved in determining if the decline in value is other than temporary. The use of alternate judgments and/or assumptions could result in the recognition of different levels of impairment charges in the financial statements.

Notes (Continued)

Significant gains or losses from asset sales, impairments and other items included in other (income) expense-net within segment costs and expenses and investing income (loss) are included in the following table.

(Millions)	Three months ended September 30, 2003	Three months ended September 30, 2002	Nine months ended September 30, 2003	Nine months ended September 30, 2002
OTHER (INCOME) EXPENSE-NET:				
POWER				
Net loss accruals and write-offs	$ --	$ 11.5	$ --	$ 95.2
Impairment of goodwill	--	--	--	57.5
Gain on sale of Jackson power contract	(13.0)	--	(188.0)	--
Commodity Futures Trading Commission settlement (see Note 11)	--	--	20.0	--
GAS PIPELINE				
Write-off of software development costs due to cancelled implementation	--	--	25.5	--
EXPLORATION & PRODUCTION				
Net gain on sale of certain natural gas properties	(2.3)	(143.9)	(96.4)	(143.9)
INVESTING INCOME (LOSS):				
POWER				
Gain on sale of marketable equity securities	13.5	--	13.5	--
GAS PIPELINE				
Write-down of				

investment in cancelled Independence Pipeline project -- -- -- (12.3) Contractual construction completion fee received by equity investee -- -- -- 27.4 Net write-down of equity interest in Alliance Pipeline -- (11.6) -- (11.6) Gain on sale of equity interest in Northern Border Partners, L.P. -- 8.7 -- 8.7 MIDSTREAM GAS & LIQUIDS Impairment of equity interest in Aux Sable (5.6) -- (14.1) -- Gain on sale of equity interest in West Texas LPG Pipeline, L.P. 11.0 -- 11.0 -- OTHER Impairment of cost based investment -- -- (13.5) -- Impairment of investment and debt securities in Longhorn Partners Pipeline, L.P. -- -- (42.4) -- Impairment of investment in Algar Telecom, S.A (1.2) -- (13.2) -- Gain on sale of blending assets 9.2 -- 9.2 -- Provision for loss on estimated recoverability of WilTel Communications Group, Inc. receivables -- (22.9) -- (269.9) Gain on sale of investment in AB Mazeikiu Nafta -- 58.5 -- 58.5

Notes (Continued)

5. Provision (benefit) for income taxes

The provision (benefit) for income taxes from continuing operations includes:

(Millions)	Three months ended September 30, 2003	Three months ended September 30, 2002	Nine months ended September 30, 2003	Nine months ended September 30, 2002
Current:				
Federal	$ 1.4	$ (100.4)	$ 13.8	$ (63.7)
State	(23.6)	10.0	(10.4)	10.0
Foreign	(.6)	10.7	9.4	10.5
	(22.8)	(79.7)	12.8	(43.2)
Deferred:				
Federal	16.4	25.2	103.0	(117.2)
State	25.8	(26.0)	20.7	(36.7)
Foreign	4.4	8.3	2.3	5.8
	46.6	7.5	126.0	(148.1)
Total provision (benefit)	$ 23.8	$ (72.2) $		

138.8 $
(191.3)
============
============
============
============

The effective income tax rate for the three months ended September 30, 2003, is greater than the federal statutory rate due primarily to foreign operations and state income taxes. For the nine months ended September 30, 2003, the effective income tax rate is greater than the federal statutory rate due primarily to nondeductible expenses, state income taxes, foreign operations, the financial impairment of certain investments, and capital losses generated for which valuation allowances were established.

The effective income tax rate for the three months ended September 30, 2002, is less than the federal statutory rate due primarily to foreign operations which reduce the tax benefit of the pretax loss. For the nine months ended September 30, 2002, the effective income tax rate is less than the federal statutory rate due primarily to the impairment of goodwill which is not deductible for income tax purposes and foreign operations both of which reduce the tax benefit of the pretax loss.

6. Discontinued operations
- ---

During 2002, Williams began the process of selling assets and/or businesses to address liquidity issues. The businesses discussed below represent components of Williams that have been sold or approved for sale by the board of directors as of September 30, 2003; therefore, their results of operations (including any impairments, gains or losses), financial position and cash flows have been reflected in the consolidated financial statements and notes as discontinued operations.

Summarized results of discontinued operations for the three and nine months ended September 30, 2003 and 2002 are as follows:

(Millions)	Three months ended September 30, 2003	Three months ended September 30, 2002	Nine months ended September 30, 2003	Nine months ended September 30, 2002
Revenues	$ 440.1	$ 1,451.1	$ 2,177.9	$ 4,249.6
Income from discontinued operations before income taxes	$ 13.1	$ 43.9	$ 124.7	$ 233.5
(Impairments) and gain (loss) on sales - net	72.3	(231.4)	187.9	(340.6)
(Provision) benefit for income taxes				

(1.9) 64.6
(89.5) 32.1

Total income
(loss) from
discontinued
operations $
83.5 $
(122.9) $
223.1 $
(75.0)
============
============
============
============

Notes (Continued)

Summarized assets and liabilities of discontinued operations as of September 30, 2003 and December 31, 2002, are as follows:

(Millions)	September 30, 2003	December 31, 2002
Total current assets	$ 148.0	$ 723.9
Property, plant and equipment - net	279.5	3,212.3
Other noncurrent assets	1.9	268.5
Total noncurrent assets	281.4	3,480.8
Total assets	$ 429.4	$ 4,204.7
Reflected on balance sheet as:		
Current assets	$ 429.4	$ 1,263.6
Noncurrent assets	--	2,941.1
Total assets	$ 429.4	$ 4,204.7
Long-term debt due within one year	$ --	$ 68.7
Other current liabilities	79.7	445.1
Total current liabilities	79.7	513.8

```
--- Long-
term debt
.3 828.3
Minority
interests -
- 340.0
Other
noncurrent
liabilities
6.6 108.0 -
-----------
-----------
- Total
noncurrent
liabilities
6.9 1,276.3
-----------
- ---------
--- Total
liabilities
$ 86.6 $
1,790.1
============
============
Reflected
on balance
sheet as:
Current
liabilities
$ 86.6 $
532.1
Noncurrent
liabilities
-- 1,258.0
-----------
- ---------
--- Total
liabilities
$ 86.6 $
1,790.1
============
============
```

HELD FOR SALE AT SEPTEMBER 30, 2003

Alaska refining, retail and pipeline operations

The Company is currently engaged in negotiations to sell its Alaska refinery and related assets. During first-quarter 2003, management revised its assessment of the estimated fair value of these assets, reflective of information obtained through continuing sales negotiations, using a probability-weighted approach. As a result, an impairment charge of $8 million was recognized in first-quarter 2003 and is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. During second-quarter 2003, Williams' board of directors approved a plan authorizing management to negotiate and facilitate a sale of these operations. A sale is expected to be completed within one year of that approval. These operations were part of the previously reported Petroleum Services segment.

Gulf Liquids New River Project LLC

During second-quarter 2003, Williams' board of directors approved a plan authorizing management to negotiate and facilitate a sale of these assets. An impairment charge of $92.6 million was recognized during second-quarter 2003 to reduce the carrying cost of the long-lived assets to management's estimate of fair value less estimated costs to sell the assets, and is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. Fair value was estimated based on a discounted cash flow analysis. The sale of these operations is expected to be completed within one year of the board's approval. These operations were part of the Midstream Gas & Liquids segment.

2003 COMPLETED TRANSACTIONS

Canadian liquids operations

During the third quarter of 2003, Williams completed the sale of certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at its Redwater, Alberta plant for total proceeds of approximately $228 million in cash and a $17.7 million short-term note receivable. Williams recognized pre-tax gains totaling $86.6 million on the sales which are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. These operations were part of the Midstream Gas & Liquids segment.

Soda ash operations

On September 9, 2003, Williams completed the sale of its soda ash mining facility located in Colorado. The December 31, 2002 carrying value reflected the then estimated fair value less cost to sell. During 2003, ongoing sale negotiations continued to provide new information regarding estimated fair value, and, as a result, additional impairment charges of $17.4 million were recognized in 2003. Williams recognized a loss on the sale of $4.2 million. These impairments, the loss on the sale and $92.3 million of 2002 impairments (including $48.2 million during third-quarter 2002), are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. The soda ash operations were part of the previously reported International segment.

Williams Energy Partners

On June 17, 2003, Williams completed the sale of its 100 percent general partnership interest and 54.6 percent limited partner investment in Williams Energy Partners for approximately $512 million in cash and assumption by the purchasers of $570 million in debt. Williams recognized a pre-tax gain of $275.6 million on the sale, which is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. The Company deferred an additional $113 million associated with Williams' indemnifications of the purchasers for a variety of matters, including obligations that may arise associated with existing environmental contamination relating to operations prior to April 2002 and identified prior to April 2008 (see Note 11).

Bio-energy facilities

On May 30, 2003, Williams completed the sale of its bio-energy operations for approximately $59 million in cash. The December 31, 2002 carrying value reflected the estimated fair value less cost to sell. During second-quarter 2003, Williams recognized an additional pre-tax loss on the sale of $6.4 million. Third-quarter 2002 included an impairment charge of $144.3 million. Both the additional loss and impairment charge are included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

Texas Gas

On May 16, 2003, Williams completed the sale of Texas Gas Transmission Corporation for $795 million in cash and the assumption by the purchaser of $250 million in existing Texas Gas debt. This business was evaluated for recoverability at March 31, 2003 on a held-for-use basis pursuant to SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." As a result, a $109 million impairment charge was recorded in first-quarter 2003 reflecting the excess of the carrying cost of the long-lived assets over management's estimate of fair value based on management's assessment of the expected sales price pursuant to the purchase and sale agreement. The impairment charge is included in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. No significant gain or loss was recognized on the sale. Texas Gas was a segment within Gas Pipeline.

Natural gas properties

On May 30, 2003, Williams completed the sale of natural gas exploration and production properties in the Raton Basin in southern Colorado and the Hugoton Embayment of the Anadarko Basin in southwestern Kansas. This sale included all of Williams' interests within these basins. A $39.9 million gain on the sale was recognized during second-quarter 2003 and is included in (impairments) and gain (loss) on sale in the preceding table of summarized results of discontinued operations. These properties were part of the Exploration & Production segment.

Midsouth refinery and related assets

On March 4, 2003, Williams completed the sale of its refinery and other related operations located in Memphis, Tennessee for approximately $455 million in cash. These assets were previously written down by $240.8 million (including $176.2 million during third-quarter 2002) to their estimated fair value less cost to sell at December 31, 2002. A pre-tax gain on sale of $4.7 million was recognized in the first quarter of 2003. During the second quarter of 2003, Williams recognized a $24.7 million pre-tax gain on the sale of an earn-out agreement retained by Williams in the sale of the refinery. The second-quarter 2002 impairment charge together with the gains are included in (impairments) and gain (loss) on sale in the preceding table of summarized results of discontinued operations. These operations were part of the previously reported Petroleum Services segment.

Williams travel centers

On February 27, 2003, Williams completed the sale of the travel centers for approximately $189 million in cash. The December 31, 2002 carrying value reflected the estimated fair value less cost to sell. Included in (impairments) and gain (loss) on sale in the preceding table of summarized results of discontinued operations are impairment charges of $112.1 million and $139.1 million for the three and nine months ended September 30, 2002, respectively. No significant gain or loss was recognized on the sale. These operations were part of the previously reported Petroleum Services segment.

2002 COMPLETED TRANSACTIONS

Central

On November 15, 2002, Williams completed the sale of its Central natural gas pipeline for $380 million in cash and the assumption by the purchaser of $175 million in debt. A third-quarter 2002 impairment charge of $86.9 million is reflected in (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations. Central was a segment within Gas Pipeline.

Mid-America and Seminole Pipelines

On August 1, 2002, Williams completed the sale of its 98 percent interest in Mid-America Pipeline and 98 percent of its 80 percent ownership interest in Seminole Pipeline for $1.2 billion. The sale generated net cash proceeds of $1.15 billion. In the preceding table of summarized results of discontinued operations, (impairments) and gain (loss) on sales includes a pre-tax gain of $304.6 million in third-quarter 2002 and a $9 million reduction of the gain in third-quarter 2003. These assets were part of the Midstream Gas & Liquids segment.

Kern River

On March 27, 2002, Williams completed the sale of its Kern River pipeline for $450 million in cash and the assumption by the purchaser of $510 million in debt. As part of the agreement, $32.5 million of the purchase price was contingent upon Kern River receiving a certificate from the FERC to construct and operate a future expansion. This certificate was received in July 2002, and the contingent payment plus interest was recognized as income from discontinued operations in third-quarter 2002. Included as a component of (impairments) and gain (loss) on sales in the preceding table of summarized results of discontinued operations is a pre-tax gain of $31.7 million and a pre-tax loss of $6.4 million for the three and nine months ended September 30, 2002, respectively. Kern River was a segment within Gas Pipeline.

Notes (Continued)

7. Earnings (loss) per share

Basic and diluted earnings (loss) per common share are computed as follows:

(Dollars in millions, except per-share amounts; shares in thousands)	Three months ended September 30, 2003	Three months ended September 30, 2002	Nine months ended September 30, 2003	Nine months ended September 30, 2002
Income (loss) from continuing operations	$ 22.8	$ (171.2)	$ 99.7	$ (460.5)
Convertible preferred stock dividends	--	(6.8)	(29.5)	(83.3)
Income (loss) from continuing operations available to common stockholders for basic and diluted earnings per share	22.8	(178.0)	70.2	(543.8)
Basic weighted-average shares				

	518,292	516,901	518,014	516,688
Effect of dilutive securities:				
Stock options	4,155	--	3,261	--
Deferred shares unvested	2,264	--	2,663	--
Diluted weighted-average shares	524,711	516,901	523,938	516,688
Earnings (loss) per share from continuing operations:				
Basic	$ .05	$ (.34)	$ .14	$ (1.05)
Diluted	$ .04	$ (.34)	$ .13	$ (1.05)

For the nine months ended September 30, 2003, approximately 8.6 million weighted average shares related to the assumed conversion of 9 7/8 percent cumulative convertible preferred stock have been excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive. The preferred stock was redeemed in June 2003.

For the three and nine months ended September 30, 2003, approximately 10.2 and 6.9 million weighted-average shares, respectively, related to the assumed conversion of convertible debentures, as well as the related interest, were excluded from the computation of diluted earnings per common share as their inclusion would be antidilutive.

For the three and nine months ended September 30, 2002, diluted earnings (loss) per share is the same as the basic calculation. The inclusion of any stock options, convertible preferred stock and unvested deferred stock would be antidilutive as Williams reported a loss from continuing operations for these periods. As a result, approximately 7,600 and 880,000 weighted-average stock options for the three and nine months ended September 30, 2002, respectively, that otherwise would have been included, were excluded from the computation of diluted earnings per common share. Additionally, approximately 14.7 million and 10.1 million weighted-average shares for the three and nine months ended September 30, 2002, respectively, related to the assumed conversion of 9 7/8 percent cumulative convertible preferred stock and approximately 4.1 million and 3.5 million weighted-average unvested deferred shares for the three and nine months ended September 30, 2002, respectively, have been excluded from the computation of diluted earnings per common share.

Notes (Continued)

8. Stock-based compensation

Employee stock-based awards are accounted for under Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" (APB 25) and related interpretations. Fixed-plan common stock options generally do not result in compensation expense because the exercise price of the stock options equals the market price of the underlying stock on the date of grant. The following table illustrates the effect on net income (loss) and earnings (loss) per share if the company had applied the fair value recognition provisions of SFAS No. 123 "Accounting for Stock-Based Compensation."

	Three months ended September 30,		Nine months ended September 30,	
(Millions)	2003	2002	2003	2002
Net income (loss), as reported	$ 106.3	$ (294.1)	$ (438.5)	$ (535.5)
Add: Stock-based employee compensation included in the Consolidated Statement of Operations, net of related tax effects	3.1	5.4	17.0	13.5
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(6.7)	(9.3)	(27.7)	(24.8)

- ---------
--- Pro
forma net
income
(loss) $
102.7 $
(298.0) $
(449.2) $
(546.8)
============
============
============
============
Earnings
(loss) per
share:
Basic-as
reported $
.21 $ (.58)
$ (.90) $
(1.20)
Basic-pro
forma $ .20
$ (.59) $
(.92) $
(1.22)
Diluted-as
reported $
.20 $ (.58)
$ (.89) $
(1.20)
Diluted-pro
forma $ .20
$ (.59) $
(.91) $
(1.22)
============
============
============
============

Pro forma amounts for 2003 include compensation expense from Williams awards made in 2003, 2002 and 2001. Pro forma amounts for 2002 include compensation expense from Williams awards made in 2002 and 2001 and from certain Williams awards made in 1999.

Since compensation expense for stock options is recognized over the future years' vesting period for pro forma disclosure purposes and additional awards are generally made each year, pro forma amounts may not be representative of future years' amounts.

On May 15, 2003, Williams' shareholders approved a stock option exchange program. Under this exchange program, eligible Williams employees were given a one-time opportunity to exchange certain outstanding options for a proportionately lesser number of options at an exercise price to be determined at the grant date of the new options. Surrendered options were cancelled June 26, 2003, and replacement options will be granted no earlier than six months and one day after the cancellation date of each surrendered option. Under APB 25, Williams will not recognize any expense pursuant to the stock option exchange. However, for purposes of pro forma disclosures, Williams will recognize additional expense related to these new options and the remaining expense on the cancelled options.

9. Inventories

Inventories at September 30, 2003 and December 31, 2002 are as follows:

(Millions)	September 30, 2003	December 31, 2002
Raw materials:		
Crude oil	$ 1.8	$ 3.8
	1.8	3.8
Finished goods:		
Refined products	19.1	47.7
Natural gas liquids	47.5	102.9
General merchandise	1.1	1.1
	67.7	151.7
Materials and supplies	65.9	87.2
Natural gas in underground storage	134.6	125.4
	$ 270.0	$ 368.1

Effective January 1, 2003, Williams adopted EITF Issue No. 02-3 (see Note 3). As a result, Williams reduced the recorded value of natural gas in underground storage by $37.0 million, refined products by $2.9 million and natural gas liquids by $1.0 million.

Notes (Continued)

10. Debt and banking arrangements
- ---

NOTES PAYABLE AND LONG-TERM DEBT

Notes payable and long-term debt at September 30, 2003 and December 31, 2002, are as follows:

Weighted-
Average
Interest
September
30, December
31,
(Millions)
Rate (1)
2003 2002 --
---------- -

Secured
notes
payable
6.57% $ 6.6
$ 934.8
============
============
============
Long-term
debt:
Secured
long-term
debt
Revolving
credit loans
-- $ -- $
81.0
Debentures,
9.875%,
payable 2020
9.9% 28.7
28.7 Notes,
9.17%-9.45%,
payable
through 2013
9.4% 121.6
256.8 Notes,
adjustable
rate,
payable
through 2007
4.9% 500.4
5.2 Other,
payable 2003
-- -- 20.9
Unsecured
long-term
debt
Debentures,
5.5%-10.25%,
payable
through 2033
7.1% 1,742.5
1,449.0
Notes,
6.125%-9.25%,
payable
through 2032
(2) 7.8%
10,430.8
9,349.9
Notes,
adjustable
rate -- --
669.9 Other,
payable

through 2005
4.3% 79.4
158.1
Capital
leases -- --
139.9 ------
------ -----

12,903.4
12,159.4
Long-term
debt due
within one
year
(1,913.3)
(1,082.7) --
---------- -

Total long-
term debt $
10,990.1 $
11,076.7
============
============

(1) At September 30, 2003.

(2) Includes $1.1 billion of 6.5 percent notes, payable 2007 subject to remarketing in 2004 (FELINE PACS). If a remarketing is unsuccessful in 2004 and a second remarketing in February 2005 is unsuccessful as defined in the offering document for the FELINE PACS, then Williams could exercise its right to foreclose on the notes in order to satisfy the obligation of the holders of the equity forward contracts requiring the holder to purchase Williams common stock.

Notes payable at December 31, 2002, included a $921.8 million secured note (the RMT note payable), which was repaid in May 2003 with proceeds from asset sales and proceeds from a $500 million new long-term debt obligation (described below under "Issuances and Retirements").

In the third quarter of 2003, Williams' Board of Directors authorized the Company to retire or otherwise prepay up to $1.8 billion of debt, including $1.4 billion designated for the Company's 9.25 percent notes due March 15, 2004. On October 8, 2003, Williams announced a cash tender offer for any and all of Williams' $1.4 billion senior unsecured 9.25 percent notes as well as cash tender offers and consent solicitations for approximately $241 million of additional outstanding notes and debentures. As of October 31, 2003, approximately $720 million of the 9.25 percent notes had been accepted for purchase. Additionally, Williams received tenders of notes and deliveries of related consents from holders of approximately $230 million of the other notes and debentures. As a result of the tendered notes and related consents at October 31, 2003, a premium of approximately $56 million will be reflected in fourth-quarter 2003 as a charge to earnings.

Williams ensures that the interest rates received by foreign lenders under various loan agreements are not reduced by taxes by providing for the reimbursement of any domestic taxes required to be paid by the foreign lender. The maximum potential amount of future payments under these indemnifications is based on the related borrowings, generally continue indefinitely unless limited by the underlying tax regulations, and have no carrying value. Williams has never been called upon to perform under these indemnifications.

REVOLVING CREDIT AND LETTER OF CREDIT FACILITIES

On June 6, 2003, Williams entered into a two-year $800 million revolving credit facility, primarily for the purpose of issuing letters of credit. Williams, Northwest Pipeline and Transco have access to all unborrowed amounts under the facility. The facility must be secured by cash and/or acceptable government securities with a market value of at least 105 percent of the then outstanding aggregate amount available for drawing under all letters of credit, plus the aggregate amount of all loans then outstanding. The restricted cash and investments used as collateral are classified on the balance sheet as current or non-current based on the expected ultimate termination date of the underlying debt or letters of credit. The new credit facility replaced a $1.1 billion credit line entered into in July 2002 that was comprised of a $700 million secured revolving credit facility and a $400 million secured letter of credit facility. The previous agreements were secured by substantially all of the Company's Midstream Gas & Liquids assets. The new agreement released these assets as collateral. The interest rate on the new agreement is variable at the London InterBank Offered Rate (LIBOR) plus .75 percent. As of September 30, 2003, letters of credit totaling $422 million have been issued by the participating financial institutions under this facility and remain outstanding. No revolving credit loans were outstanding. At September 30, 2003, the amount of restricted investments securing this facility was $443.7 million, which collateralized the facility at 105.14 percent.

ISSUANCES AND RETIREMENTS

On May 28, 2003, Williams issued $300 million of 5.5 percent junior subordinated convertible debentures due 2033. These notes, which are callable by the Company after seven years, are convertible at the option of the holder into Williams common stock at a conversion price of approximately $10.89 per share. The proceeds were used to redeem all of the outstanding 9 7/8 percent cumulative-convertible preferred shares (see Note 12).

On May 30, 2003, a subsidiary of Williams entered into a $500 million secured note due May 30, 2007, at a floating interest rate of six-month LIBOR plus 3.75 percent (totaling 4.9 percent at September 30, 2003). This loan refinances a portion of the RMT note discussed above. Certain of Williams' Exploration & Production interests in the U.S. Rocky Mountains had secured the RMT note payable and now serve as security on the new loan. Significant covenants on the borrowers, RMT and Williams Production Holdings LLC (Holdings) (parent of RMT), include: (i) an interest coverage ratio computed on a consolidated RMT basis of greater than 3 to 1, (ii) a ratio of the present value of future cash flows of proved reserves, discounted at ten percent, based on the most recent engineering report to total senior secured debt, computed on a consolidated RMT basis, of greater than 1.75 to 1, (iii) a limitation on restricted payments and (iv) a limitation on intercompany indebtedness.

On June 10, 2003, Williams issued $800 million of 8.625 percent senior unsecured notes due 2010. The notes were issued under the company's $3 billion shelf registration statement. Significant covenants include: i) limitation on certain payments, including a limitation on the payment of quarterly dividends to no greater than $.02 per common share; ii) limitation on additional indebtedness and issuance of preferred stock unless the Fixed Charge Coverage Ratio for the Company's most recently ended four full fiscal quarters is at least 2 to 1, determined on a proforma basis; iii) limitation on asset sales, unless the consideration is at least equal to fair market value and at least 75 percent of the consideration received is in the form of cash or cash equivalents; iv) a limitation on the use of proceeds from permitted asset sales; and v) a limitation on transactions with affiliates. These restrictions may be lifted if certain conditions, including Williams attaining an investment grade rating from both Moody's Investors Service and Standard and Poor's, are met.

A summary of significant long-term debt, including capital leases, issuances and retirements, as well as the items listed above, for the nine months ended September 30, 2003, are as follows:

Principal Issue/Terms
Due Date Amount ------
--- ----------
(Millions) Issuances
of long-term debt in
2003: 8.125% senior
notes (Northwest
Pipeline) 2010 $ 175.0
RMT term loan B
(Exploration &

Production) 2007 $ 500.0 5.5% junior subordinated convertible debentures 2033 $ 300.0 8.625% senior unsecured notes 2010 $ 800.0 Retirements/prepayments of long-term debt in 2003: Preferred interests 2003-2006 $ 302.5 Various capital leases 2005 $ 139.8 Various notes, 6.65% - 9.45% 2003 $ 49.9 Various notes, adjustable rate 2003-2004 $ 531.2 Various debentures 2003 $ 7.5

11. Contingent liabilities and commitments

RATE AND REGULATORY MATTERS AND RELATED LITIGATION

Williams' interstate pipeline subsidiaries have various regulatory proceedings pending. As a result of rulings in certain of these proceedings, a portion of the revenues of these subsidiaries has been collected subject to refund. The natural gas pipeline subsidiaries have accrued approximately $12 million for potential refund as of September 30, 2003.

Power subsidiaries are engaged in power marketing in various geographic areas, including California. Prices charged for power by Williams and other traders and generators in California and other western states have been challenged in various proceedings including those before the FERC. In December 2000, the FERC issued an order which provided that, for the period between October 2, 2000 and December 31, 2002, the FERC may order refunds from Williams and other similarly situated companies if the FERC finds that the wholesale markets in California were unable to produce competitive, just and reasonable prices or that market power or other individual seller conduct was exercised to produce an unjust and unreasonable rate. The judge issued his findings in the refund case on December 12, 2002. Under these findings, Williams' refund obligation to the California Independent System Operator (ISO) is $192 million, excluding emissions costs and interest. The judge found that Williams' refund obligation to the California Power Exchange (PX) is $21.5 million, excluding interest. However, the judge found that the ISO owes Williams $246.8 million, excluding interest, and that the PX owes Williams $31.7 million, excluding interest, and $2.9 million in charge backs. The judge's findings do not include the $17 million in emissions costs that the judge found Williams is entitled to use as an offset to the refund liability, and the judge's refund amounts are not based on final mitigated market clearing prices. On March 26, 2003, the FERC acted to largely adopt the judge's order with a change to the gas methodology used to set the clearing price. As a result, Power recorded a first-quarter 2003 charge for refund obligations of $37 million. Net interest income related to amounts due from the counterparties is approximately $9 million through September 30, 2003. On October 16, 2003, FERC issued an order granting rehearing in part and denying rehearing in part. This order is not expected to have a material effect on the refund calculation for Williams. Pursuant to an order from the 9th Circuit, FERC permitted the California parties to conduct additional discovery into market manipulation by sellers in the California markets. The California parties sought this discovery in order to potentially expand the scope of the refunds. On March 3, 2003, the California parties submitted evidence from this discovery on market manipulation. Williams and other sellers submitted comments to the additional evidence on March 20, 2003.

In an order issued June 19, 2001, the FERC implemented a revised price mitigation and market monitoring plan for wholesale power sales by all suppliers of electricity, including Williams, in spot markets for a region that includes California and ten other western states (the Western Systems Coordinating Council, or WSCC). In general, the plan, which was in effect from June 20, 2001 through September 30, 2002, established a market clearing price for spot sales in all hours of the day that was based on the bid of the highest-cost gas-fired California generating unit that was needed to serve the ISO's load. When generation operating reserves fell below seven percent in California (a reserve deficiency period), absent cost-based justification for a higher price, the maximum price that Williams could charge for wholesale spot sales in the WSCC was the market clearing price. When generation operating reserves rose to seven percent or above in California, absent cost-based justification for a higher price, Williams' maximum price was limited to 85 percent of the highest hourly price that was in effect during the most recent reserve deficiency period. This methodology initially resulted in a maximum price of $92 per megawatt hour during non-emergency periods and $108 per megawatt hour during emergency periods. These maximum prices remained unchanged throughout summer and fall 2001. Revisions to the plan for the post-September 30, 2002 period were provided on July 17, 2002, as discussed below.

On December 19, 2001, the FERC reaffirmed its June 19 order with certain clarifications and modifications. It also altered the price mitigation methodology for spot market transactions for the WSCC market for the winter 2001 season and set the period maximum price at $108 per megawatt hour through April 30, 2002. Under the order, this price would be subject to being recalculated when the average gas price rises by a minimum factor of ten percent effective for the following trading day, but in no event would the maximum price drop below $108 per megawatt hour. The FERC also upheld a ten percent addition to the price applicable to sales into California to reflect credit risk. On July 9, 2002, the ISO's operating reserve levels dropped below seven percent for a full operating hour, during which the ISO declared a Stage 1 System Emergency resulting in a new Market Clearing Price cap of $57.14/MWh under the FERC's rules. On July 11, 2002, the FERC issued an order that the existing price mitigation formula be replaced with a hard price cap of $91.87/MWh for spot markets operated in the West (which is the level of price mitigation that existed prior to the July 9, 2002 events that reduced the cap), to be effective July 12, 2002. The cap expired September 30, 2002, but the cap was later extended by FERC to October 30, 2002.

On July 17, 2002, the FERC issued its first order on the California ISO's proposed market redesign. Key elements of the order include (1) maintaining indefinitely the current must-offer obligation across the West; (2) the adoption of Automatic Mitigation Procedures (AMP) to identify and limit excessive bids and local market power within California, (bids less than $91.87/MWh will not be subject to AMP); (3) a West-wide spot market bid cap of $250/MWh, beginning October 1, 2002, and continuing indefinitely; (4) a requirement that the ISO expedite the following market design elements and requiring them to be filed by October 21, 2002: (a) creation of an integrated day-ahead market; (b) ancillary services market reforms; and (c) hour-ahead and real-time market reforms; and (5) the development of locational marginal pricing (LMP). The FERC reaffirmed these elements in an order issued October 9, 2002, with the following clarification: (a) generators may bid above the ISO cap, but their bids cannot set the market clearing price and they will be subject to justification and refund, (b) if the market clearing price is projected to be above $91.87 per MWh in any zone, automatic mitigation will be triggered in all zones, and (c) the ten percent creditworthiness adder will be removed effective October 31, 2002. On January 17, 2003, FERC clarified that bids below $91.87 per MWh are not entitled to a safe harbor from mitigation, and where a seller is subject to the must-offer obligation but fails to submit a bid, the ISO may impose a proxy bid. On October 31, 2002, FERC found that the ISO has not explained how it will treat generators that are running at minimum load and dispatched in accordance with ISO instruction (instructed energy). On December 2, 2002, the ISO proposed to pay for energy at minimum load the uninstructed energy price even when a unit is dispatched for instructed energy. Williams protested on January 2, 2003, arguing that the ISO's proposal fails to keep sellers whole. On March 13, 2003, FERC issued an order agreeing with Williams and other generators covering minimum load costs. Further guidance on the proposed market redesign was issued by the FERC on October 28, 2003.

In a separate but related proceeding, certain entities have also asked the FERC to revoke Williams' authority to sell power from California-based generating units at market-based rates, to limit Williams to cost-based rates for future sales from such units and to order refunds of excessive rates, with interest, retroactive to May 1, 2000, and possibly earlier.

The California Public Utilities Commission (CPUC) filed a complaint with the FERC on February 25, 2002, seeking to void or, alternatively, reform a number of the long-term power purchase contracts entered into between the State of California and several suppliers in 2001, including Power. The CPUC alleges that the contracts are tainted with the exercise of market power and significantly exceed "just and reasonable" prices. The California Electricity Oversight Board (CEOB) made a similar filing on February 27, 2002. The FERC set the complaint for hearing on April 25, 2002, but held the hearing in abeyance pending settlement discussions before a FERC judge. The FERC also ordered that the higher public interest test will apply to the contracts. The FERC commented that the state has a very heavy burden to carry in proving its case. On July 17, 2002, the FERC denied rehearing of the April 25, 2002 order that set for hearing California's challenges to the long-term contracts entered into between the state and several suppliers, including Power. The settlement discussions noted above resulted in Williams entering into a settlement agreement with the State of California and other non-Federal parties that includes renegotiated long-term energy contracts. These contracts are made up of block energy sales, dispatchable products and a gas contract. The original contract contained only block energy sales. The settlement does not extend to criminal matters or matters of willful fraud, but will resolve civil complaints brought by the California Attorney General against Williams that are discussed below and the State of California's refund claims that are discussed above. In addition, the settlement is intended to resolve ongoing investigations by the States of California, Oregon and Washington. The settlement was reduced to writing and executed on November 11, 2002. The settlement closed on December 31, 2002, after FERC issued an order granting Williams' motion for partial dismissal from the refund proceedings. The dismissal affects Williams' refund obligations to the settling parties, but not to other parties, such as investor-owned utilities. Pursuant to the settlement, the CPUC and CEOB filed a motion on January 13, 2003 to withdraw their complaints against Williams regarding the original block energy sales contract. On June 26, 2003, the FERC granted the CPUC and CEOB joint motion to withdraw their respective complaints against Williams. Private class action and other civil plaintiffs also executed the settlement. Final approval by the court is needed to make the settlement effective as to plaintiffs and to terminate the class actions as to Williams. On October 24, 2003, the court granted a motion for preliminary approval of the settlement. The final approval hearing is currently scheduled for February 20, 2004. As of September 30, 2003, pursuant to the terms of the settlement, Williams has transferred ownership of six LM6000 gas powered electric turbines, has made one payment of $42 million to the California Attorney General, and has funded a $15 million fee and expense fund associated with civil actions that are subject to the settlement. An additional $105 million remains to be paid to the California Attorney General (or his designee) over the next seven years, with the final payment of $15 million due on January 1, 2010.

On May 2, 2002, PacifiCorp filed a complaint against Power seeking relief from rates contained in three separate confirmation agreements between PacifiCorp and Power (known as the Summer 2002 90-Day Contracts). PacifiCorp filed similar complaints against three other suppliers. PacifiCorp alleges that the rates contained in the contracts are unjust and unreasonable. Power filed its answer on May 22, 2002, requesting that the FERC reject the complaint and deny the relief sought. On June 28, 2002, the FERC set PacifiCorp's complaints for hearing, but held the hearing in abeyance pending the outcome of settlement judge proceedings. The FERC set a refund effective date of July 1, 2002. The hearing was conducted December 13 through December 20, 2002, at FERC. The judge issued an initial decision on February 27, 2003 dismissing the complaints. This decision was appealed to the FERC and FERC affirmed the Administrative Law Judge (ALJ).

On March 14, 2001, the FERC issued a Show Cause Order directing Power and AES Southland, Inc. to show cause why they should not be found to have engaged in violations of the Federal Power Act and various agreements, and they were directed to make refunds in the aggregate of approximately $10.8 million and have certain conditions placed on Williams' market-based rate authority for sales from specific generating facilities in California for a limited period. On April 30, 2001, the FERC issued an Order approving a settlement of this proceeding. The settlement terminated the proceeding without making any findings of wrongdoing by Williams. Pursuant to the settlement, Williams agreed to refund $8 million to the ISO by crediting such amount against outstanding invoices. Williams also agreed to prospective conditions on its authority to make bulk power sales at market-based rates for certain limited facilities under which it has call rights for a one-year period. Williams also has been informed that the facts underlying this proceeding have been investigated by a California Grand Jury, and the investigation has been closed without the Grand Jury taking any action. As a result of federal court orders, FERC released the data it obtained from Williams that gave rise to the show cause order.

On December 11, 2002, the FERC staff informed Transcontinental Gas Pipe Line Corporation (Transco) of a number of issues the FERC staff identified during the course of a formal, nonpublic investigation into the relationship between Transco and its marketing affiliate, Power. The FERC staff asserted that Power personnel had access to Transco data bases and other information, and that Transco had failed to accurately post certain information on its electronic bulletin board. Williams, Transco and Power disagreed with some of the FERC staff's allegations and furthermore believe that Power did not profit from the alleged activities. Nevertheless, in order to avoid protracted litigation, on March 13, 2003, Williams, Transco and Power executed a settlement of this matter with the FERC staff. An Order approving the settlement was issued by the FERC on March 17, 2003. No requests for rehearing of the March 17, 2003 order were filed; therefore, the order became final on April 16, 2003. Pursuant to the terms of the settlement agreement, Transco will pay a civil penalty in the amount of $20 million, beginning with a payment of $4 million within thirty (30) days of the date the FERC Order approving the settlement becomes final. The first payment was made on May 16, 2003, and the subsequent $4 million payments are due on or before the first, second, third and fourth anniversaries of the first payment. Transco recorded a charge to income and established a liability of $17 million in 2002 on a discounted basis to reflect the future payments to be made over the next four years. In addition, Transco has provided notice to its merchant sales service customers that it will be terminating such services when it is able to do so under the terms of any applicable contracts and FERC certificates authorizing such services. Most of these sales are made through a Firm Sales (FS) program, and under this program Transco must provide two-year advance notice of termination. Therefore, Transco notified the FS customers of its intention to terminate the FS service effective April 1, 2005. As part of the settlement, Power has agreed, subject to certain exceptions, that it will not enter into new transportation agreements that would increase the transportation capacity it holds on certain affiliated interstate gas pipelines, including Transco. Finally, Transco and certain affiliates have agreed to the terms of a compliance plan designed to ensure future compliance with the provisions of the settlement agreement and the FERC's rules governing the relationship of Transco and Power.

On August 1, 2002, the FERC issued a Notice of Proposed Rulemaking (NOPR) that proposed restrictions on various types of cash management programs employed by companies in the energy industry, such as Williams and its subsidiaries. In addition to stricter guidelines regarding the accounting for and documentation of cash management or cash pooling programs, the FERC proposal, if made final, would have precluded public utilities, natural gas companies and oil pipeline companies from participating in such programs unless the parent company and its FERC-regulated affiliate maintain investment-grade credit ratings and that the FERC-regulated affiliate maintains stockholders equity of at least 30 percent of total capitalization. Williams' and its regulated gas pipelines' current credit ratings are not investment grade. Williams participated in comments in this proceeding on August 28, 2002, by the Interstate Natural Gas Association of America. On September 25, 2002, the FERC convened a technical conference to discuss the issues raised in the comments filed by parties in this proceeding. On June 26, 2003, the FERC issued an Interim Rule (Order No. 634), which replaces the earlier NOPR on cash management described above. The Interim Rule requires FERC-regulated entities to have their cash management programs in writing and to have all such programs specify (i) the duties and responsibilities of administrators and participants, (ii) the methods for calculating interest and for allocating interest and expenses, and (iii) restrictions on borrowing from the programs. The Interim Rule became effective on August 7, 2003. The Interim Rule also sought industry comment on new reporting requirements that would require FERC-regulated entities to file their cash management programs with the FERC and to notify the FERC when their proprietary capital ratio drops below 30 percent of total capitalization and when it subsequently returns to or exceeds 30 percent. On October 23, 2003, the FERC issued its Final Rule (Order No. 634-A), which adopted the filing and reporting requirements proposed in the Interim Rule, with certain modifications. Under the Final Rule, a FERC-regulated entity must file its cash management program with the FERC for informational purposes, and must compute its proprietary capital ratio quarterly and notify the FERC within 45 days after the end of each calendar quarter if its proprietary capital ratio drops below or subsequently exceeds 30 percent.

On February 13, 2002, the FERC issued an Order Directing Staff Investigation commencing a proceeding titled Fact-Finding Investigation of Potential Manipulation of Electric and Natural Gas Prices. Through the investigation, the FERC intends to determine whether "any entity, including Enron Corporation (Enron) (through any of its affiliates or subsidiaries), manipulated short-term prices for electric energy or natural gas in the West or otherwise exercised undue influence over wholesale electric prices in the West since January 1, 2000, resulting in potentially unjust and unreasonable rates in long-term power sales contracts subsequently entered into by sellers in the West." This investigation does not constitute a Federal Power Act complaint; rather, the results of the investigation will be used by the FERC in any existing or subsequent Federal Power Act or Natural Gas Act complaint. The FERC Staff is directed to complete the investigation as soon as "is practicable." Williams, through many of its subsidiaries, is a major supplier of natural gas and power in the West and, as such, anticipates being the subject of certain aspects of the investigation. Williams is cooperating with all data requests received in this proceeding. On May 8, 2002, Williams received an additional set of data requests from the FERC related to a disclosure by Enron of certain trading practices in which it may have been engaged in the California market. On May 21, and May 22, 2002, the FERC supplemented the request inquiring as to "wash" or "round trip" transactions. Williams responded on May 22, 2002, May 31, 2002, and June 5, 2002, to the data requests. On June 4, 2002, the FERC issued an order to Williams to show cause why its market-based rate authority should not be revoked as the FERC found that certain of Williams' responses related to the Enron trading practices constituted a failure to cooperate with the staff's investigation. Williams subsequently supplemented its responses to address the show cause order. On July 26, 2002, Williams received a letter from the FERC informing Williams that it had reviewed all of Williams' supplemental responses and concluded that Williams responded to the initial May 8, 2002 request.

In response to an article appearing in the New York Times on June 2, 2002, containing allegations by a former Williams employee that it had attempted to "corner" the natural gas market in California, and at Williams' invitation, the FERC is conducting an investigation into these allegations. Also, the Commodity Futures Trading Commission (CFTC) and the U.S. Department of Justice (DOJ) are conducting an investigation regarding gas and power trading and have requested information from Williams in connection with this investigation.

Williams disclosed on October 25, 2002, that certain of its gas traders had reported inaccurate information to a trade publication that published gas price indices. On November 8, 2002, Williams received a subpoena from a federal grand jury in Northern California seeking documents related to Williams' involvement in California markets, including its reporting to trade publications for both gas and power transactions. Williams is in the process of completing its response to the subpoena. The DOJ's investigation into this matter is continuing. On July 29, 2003, Williams reached a settlement with the CFTC where in exchange for $20 million, the CFTC closed its investigation and Williams did not admit or deny allegations that it had engaged in false reporting or attempted manipulation. Civil suits based on these facts have also been brought against Williams and others in state court in California and in Federal court in New York.

On March 26, 2003, FERC issued a Staff Report addressing Enron trading practices, the allegation of cornering the gas market, and the gas price index issue. The March 26, 2003 report cleared Williams on the issue of cornering the market and contemplated or established further proceedings on the other two as to Williams and numerous other market participants. On June 25, 2003, FERC issued a series of orders in response to the California parties' March 3, 2003 report on its 100 days of discovery discussed above and the Staff Report. These orders resulted in further investigations regarding potential allegations of physical withholding, economic withholding, and a show cause order to Williams and others regarding specific practices alleged by an ISO report that various companies engaged in Enron trading practices. On August 29, 2003, Williams and FERC trial staff entered into a settlement of all Enron trading practices for approximately $45,000. Certification and approval of the settlement is pending. The investigations of physical and economic withholding are also continuing.

On May 31, 2002, Williams received a request from the Securities and Exchange Commission (SEC) to voluntarily produce documents and information regarding "round-trip" trades for gas or power from January 1, 2000, to the present in the United States. On June 24, 2002, the SEC made an additional request for information including a request that Williams address the amount of Williams' credit, prudency and/or other reserves associated, with its energy trading activities and the methods used to determine or calculate these reserves. The June 24, 2002, request also requested Williams' volumes, revenues, and earnings from its energy trading activities in the Western U.S. market. Williams has responded to the SEC's requests.

On July 3, 2002, the ISO announced fines against several energy producers including Williams, for failure to deliver electricity in 2001 as required. The ISO fined Williams $25.5 million, which will be offset against Williams' claims for payment from the ISO. Williams believes the vast majority of fines are not justified and has challenged the fines pursuant to the FERC approved process contained in the ISO tariff.

On December 3, 2002, an administrative law judge at the FERC issued an initial decision in Transco's general rate case which, among other things, rejects the recovery of the costs of Transco's Mobile Bay expansion project from its shippers on a "rolled-in" basis and finds that incremental pricing for the Mobile Bay expansion project is just and reasonable. The initial decision does not address the issue of the effective date for the change to incremental pricing, although Transco's rates reflecting recovery of the Mobile Bay expansion project costs on a "rolled-in" basis have been in effect since September 1, 2001. The administrative law judge's initial decision is subject to review by the FERC. Power holds long-term transportation capacity on the Mobile Bay expansion project. If the FERC adopts the decision of the administrative law judge on the pricing of the Mobile Bay expansion project and also requires that the decision be implemented effective September 1, 2001, Power could be subject to surcharges of approximately $37 million, excluding interest, through September 30, 2003, in addition to increased costs going forward.

ENVIRONMENTAL MATTERS

Continuing operations

Since 1989, Transco has had studies under way to test certain of its facilities for the presence of toxic and hazardous substances to determine to what extent, if any, remediation may be necessary. Transco has responded to data requests regarding such potential contamination of certain of its sites. The costs of any such remediation will depend upon the scope of the remediation. At September 30, 2003, Transco had accrued liabilities totaling approximately $29 million for these costs.

Transco has identified polychlorinated biphenyl (PCB) contamination in air compressor systems, soils and related properties at certain compressor station sites. Transco has also been involved in negotiations with the U.S. Environmental Protection Agency (EPA) and state agencies to develop screening, sampling and cleanup programs. In addition, Transco commenced negotiations with certain environmental authorities and other programs concerning investigative and remedial actions relative to potential mercury contamination at certain gas metering sites. Transco had accrued liabilities for these costs which are included in the $29 million liability mentioned above.

Williams and its subsidiaries also accrue environmental remediation costs for its natural gas gathering and processing facilities, primarily related to soil and groundwater contamination. At September 30, 2003, Williams and its subsidiaries had accrued liabilities totaling approximately $9 million for these costs.

Actual costs incurred for these matters will depend on the actual number of contaminated sites identified, the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors.

Former operations, including operations classified as discontinued

In connection with the sale of certain assets and businesses, Williams has retained responsibility, through indemnification of the purchasers, for environmental and other liabilities existing at the time the sale was consummated. These assets and businesses include former fertilizer operations, propane marketing operations, retail petroleum and refining operations, petroleum products pipelines and related facilities, natural gas liquids fractionation and related facilities, exploration and production operations and mining operations.

In connection with the 1987 sale of the assets of Agrico Chemical Company, Williams agreed to indemnify the purchaser for environmental cleanup costs resulting from certain conditions at specified locations, to the extent such costs exceed a specified amount. At September 30, 2003, Williams had accrued approximately $9 million for such excess costs.

At September 30, 2003, Williams had accrued environmental liabilities totaling approximately $17 million related to its (1) Alaska refining, retail and pipeline operations currently classified as held for sale, (2) potential indemnification obligations to purchasers of its former retail petroleum and refining operations, and (3) former propane marketing operations, petroleum products and natural gas pipelines, natural gas liquids fractionation, a discontinued petroleum refining facility and exploration and production and mining operations. These costs include (1) certain conditions at specified locations related primarily to soil and groundwater contamination and (2) any penalty assessed on Williams Refining & Marketing, LLC (Williams Refining) associated with noncompliance with EPA's benzene waste "NESHAP" regulations. In 2002, Williams Refining submitted to the EPA a self-disclosure letter indicating noncompliance with those regulations. This unintentional noncompliance had occurred due to a regulatory interpretation that resulted in under-counting the total annual benzene level at Williams Refinery's Memphis refinery. Also in 2002, the EPA conducted an all-media audit of the Memphis refinery. The EPA anticipates releasing a report of its audit findings in 2003. The EPA will likely assess a penalty on Williams Refining due to the benzene waste NESHAP issue, but the amount of any such penalty is not known. In connection with the sale of the Memphis refinery in March 2003, Williams indemnified the purchaser for any such penalty.

As part of its June 17, 2003 sale of Williams Energy Partners (see Note 6), Williams indemnified the purchaser for (1) environmental cleanup costs resulting from certain conditions, primarily soil and groundwater contamination, at specified locations, to the extent such costs exceed a specified amount and (2) currently unidentified environmental contamination relating to operations prior to April of 2002 and identified prior to April of 2008. At September 30, 2003, Williams had accrued liabilities totaling approximately $8 million for these costs. In addition, Williams deferred a portion of the gain associated with Williams' indemnifications, including environmental indemnifications, of the purchaser under the sales agreement. At September 30, 2003, Williams has a remaining deferred gain relating to this sale of approximately $100 million.

On July 2, 2001, the EPA issued an information request asking for information on oil releases and discharges in any amount from Williams' pipelines, pipeline systems, and pipeline facilities used in the movement of oil or petroleum products, during the period from July 1, 1998 through July 2, 2001. In November 2001, Williams furnished its response.

Certain Williams' subsidiaries have been identified as potentially responsible parties (PRP) at various Superfund and state waste disposal sites. In addition, these subsidiaries have incurred, or are alleged to have incurred, various other hazardous materials removal or remediation obligations under environmental laws. Although no assurances can be given, Williams does not believe that these obligations or the PRP status of these subsidiaries will have a material adverse effect on its financial position, results of operations or net cash flows.

Actual costs incurred for these matters will depend on the actual number of contaminated sites identified, the actual amount and extent of contamination discovered, the final cleanup standards mandated by the EPA and other governmental authorities and other factors.

OTHER LEGAL MATTERS

In connection with agreements to resolve take-or-pay and other contract claims and to amend gas purchase contracts, Transco entered into certain settlements with producers which may require the indemnification of certain claims for additional royalties which the producers may be required to pay as a result of such settlements. Transco, through its agent, Power, continues to purchase gas under contracts which extend, in some cases, through the life of the associated gas reserves. Certain of these contracts contain royalty indemnification provisions which have no carrying value. Producers have received and may receive other demands, which could result in claims pursuant to royalty indemnification provisions. Indemnification for royalties will depend on, among other things, the specific lease provisions between the producer and the lessor and the terms of the agreement between the producer and Transco. Consequently, the potential maximum future payments under such indemnification provisions cannot be determined.

As a result of these settlements, Transco has been sued by certain producers seeking indemnification from Transco. Transco is currently defending two lawsuits in which producers have asserted damages, including interest calculated through September 30, 2003, of approximately $18 million. In one of these cases, at the conclusion of a trial on July 11, 2003, the judge ruled from the bench in Transco's favor and subsequently entered a formal judgment reflecting his bench ruling. The plaintiff is seeking an appeal. This case accounts for approximately $10 million of the $18 million claimed in the two cases. In the other case Transco and the producer have agreed in principle to settle the case, subject to the negotiation of a formal settlement agreement.

On June 8, 2001, fourteen Williams entities were named as defendants in a nationwide class action lawsuit which had been pending against other defendants, generally pipeline and gathering companies, for more than one year. The plaintiffs allege that the defendants, including the Williams defendants, have engaged in mismeasurement techniques that distort the heating content of natural gas, resulting in an alleged underpayment of royalties to the class of producer plaintiffs. In September 2001, the plaintiffs voluntarily dismissed two of the fourteen Williams entities named as defendants in the lawsuit. In January 2002, most of the Williams defendants, along with a group of Coordinating Defendants, filed a motion to dismiss for lack of personal jurisdiction and other grounds. On August 19, 2002, the defendants' motion to dismiss on nonjurisdictional grounds was denied. On September 17, 2002, the plaintiffs filed a motion for class certification. The Williams entities joined with other defendants in contesting certification of the class. On April 10, 2003, the court denied the plaintiffs' motion for class certification. The motion to dismiss for lack of personal jurisdiction remains pending. On May 13, 2003, plaintiffs filed a motion for leave to file a fourth amended petition and on July 29, 2003, the court granted the plaintiffs' motion. The amended petition deletes all of the Williams defendants except two Midstream subsidiaries.

In 1998, the DOJ informed Williams that Jack Grynberg, an individual, had filed claims in the United States District Court for the District of Colorado under the False Claims Act against Williams and certain of its wholly owned subsidiaries. The claim sought an unspecified amount of royalties allegedly not paid to the federal government, treble damages, a civil penalty, attorneys' fees, and costs. In connection with its sales of Kern River and Texas Gas, the Company agreed to indemnify the purchasers for any liability relating to this claim, including legal fees. The maximum amount of future payments that Williams could potentially be required to pay under these indemnifications depends upon the ultimate resolution of the claim and cannot currently be determined. No amounts have been accrued for these indemnifications. Grynberg has also filed claims against approximately 300 other energy companies and alleged that the defendants violated the False Claims Act in connection with the measurement, royalty valuation and purchase of hydrocarbons. On April 9, 1999, the DOJ announced that it was declining to intervene in any of the Grynberg qui tam cases, including the action filed against the Williams entities in the United States District Court for the District of Colorado. On October 21, 1999, the Panel on Multi-District Litigation transferred all of the Grynberg qui tam cases, including those filed against Williams, to the United States District Court for the District of Wyoming for pre-trial purposes. On October 9, 2002, the court granted a motion to dismiss Grynberg's royalty valuation claims. Grynberg's measurement claims remain pending against Williams and the other defendants.

On August 6, 2002, Jack J. Grynberg, and Celeste C. Grynberg, Trustee on Behalf of the Rachel Susan Grynberg Trust, and the Stephen Mark Grynberg Trust, served Williams and Williams Production RMT Company with a complaint in the District Court in and for the City of Denver, State of Colorado. The complaint alleges that the defendants have used mismeasurement techniques that distort the BTU heating content of natural gas, resulting in the alleged underpayment of royalties to Grynberg and other independent natural gas producers. The complaint also alleges that defendants inappropriately took deductions from the gross value of their natural gas and made other royalty valuation errors. Theories for relief include breach of contract, breach of implied covenant of good faith and fair dealing, anticipatory repudiation, declaratory relief, equitable accounting, civil theft, deceptive trade practices, negligent misrepresentation, deceit based on fraud, conversion, breach of fiduciary duty, and violations of the state racketeering statute. Plaintiff is seeking actual damages of between $2 million and $20 million based on interest rate variations, and punitive damages in the amount of approximately $1.4 million dollars. On October 7, 2002, the Williams defendants filed a motion to stay the proceedings in this case based on the pendency of the False Claims Act litigation discussed in the preceding paragraph. The motion to stay the proceedings was granted on January 15, 2003.

Williams and certain of its subsidiaries are named as defendants in various putative, nationwide class actions brought on behalf of all landowners on whose property the plaintiffs have alleged WilTel Communications Group, Inc. (WilTel) installed fiber-optic cable without the permission of the landowners. Williams and its subsidiaries have been dismissed from all of the cases.

In November 2000, class actions were filed in San Diego, California Superior Court by Pamela Gordon and Ruth Hendricks on behalf of San Diego rate payers against California power generators and traders including Williams Energy Services and Power, subsidiaries of Williams. Three municipal water districts also filed a similar action on their own behalf. Other class actions have been filed on behalf of the people of California and on behalf of commercial restaurants in San Francisco Superior Court. These lawsuits result from the increase in wholesale power prices in California that began in the summer of 2000. Williams is also a defendant in other litigation arising out of California energy issues. The suits claim that the defendants acted to manipulate prices in violation of the California antitrust and unfair business practices statutes and other state and federal laws. Plaintiffs are seeking injunctive relief as well as restitution, disgorgement, appointment of a receiver, and damages, including treble damages. These cases have all been administratively consolidated in San Diego County Superior Court. As part of a comprehensive settlement with the State of California and other parties, Williams and the lead plaintiffs in these suits have resolved the claims. While the settlement is final as to the State of California, the San Diego Superior Court must still approve it as to the plaintiff ratepayers. Preliminary approval was granted on October 24, 2003 and a hearing on final approval is scheduled for February 20, 2004.

On May 2, 2001, the Lieutenant Governor of the State of California and Assemblywoman Barbara Matthews, acting in their individual capacities as members of the general public, filed suit against five companies and fourteen executive officers, including Power and Williams' then current officers Keith Bailey, Chairman and CEO of Williams, Steve Malcolm, President and CEO of Williams Energy Services and an Executive Vice President of Williams, and Bill Hobbs, Senior Vice President of Power, in Los Angeles Superior State Court alleging State Antitrust and Fraudulent and Unfair Business Act Violations and seeking injunctive and declaratory relief, civil fines, treble damages and other relief, all in an unspecified amount. This case is being administratively consolidated with the other class actions in San Diego Superior Court. As part of a comprehensive settlement with the State of California and other parties, Williams and the lead plaintiffs in these suits have resolved the claims. While the settlement is final as to the State of California, the San Diego Superior Court must still approve it as to the plaintiffs in this suit as discussed above.

On October 5, 2001, a suit was filed on behalf of California taxpayers and electric ratepayers in the Superior Court for the County of San Francisco against the Governor of California and 22 other defendants consisting of other state officials, utilities and generators, including Power. The suit alleges that the long-term power contracts entered into by the state with generators are illegal and unenforceable on the basis of fraud, mistake, breach of duty, conflict of interest, failure to comply with law, commercial impossibility and change in circumstances. Remedies sought include rescission, reformation, injunction, and recovery of funds. Private plaintiffs have also brought five similar cases against Williams and others on similar grounds. These suits have all been removed to federal court, and plaintiffs are seeking to remand the cases to state court. In January 2003, the federal district court granted the plaintiffs' motion to remand the case to San Diego Superior Court, but on February 20, 2003, the United States Court of Appeals for the Ninth Circuit, on its own motion, stayed the remand order pending its review of an appeal of the remand order by certain defendants. As part of a comprehensive settlement with the State of California and other parties, Williams and the lead plaintiffs in these suits have resolved the claims. While the settlement is final as to the State of California, once the jurisdictional issue is resolved, either the San Diego Superior Court or the United States District Court for the Southern District of California must still approve the settlement as to the plaintiff ratepayers and taxpayers.

Numerous shareholder class action suits have been filed against Williams in the United States District Court for the Northern District of Oklahoma. The majority of the suits allege that Williams and co-defendants, WilTel and certain corporate officers, have acted jointly and separately to inflate the stock price of both companies. Other suits allege similar causes of action related to a public offering in early January 2002, known as the FELINE PACS offering. These cases were filed against Williams, certain corporate officers, all members of Williams' board of directors and all of the offerings' underwriters. These cases have all been consolidated and an order has been issued requiring separate amended consolidated complaints by Williams and WilTel equity holders. The amended complaint of the WilTel securities holders was filed on September 27, 2002, and the amended complaint of the Williams securities holders was filed on October 7, 2002. This amendment added numerous claims related to Power. In addition, four class action complaints have been filed against Williams, the members of its board of directors and members of Williams' Benefits and Investment Committees under the Employee Retirement Income Security Act (ERISA) by participants in Williams' 401(k) plan. A motion to consolidate these suits has been approved. Williams and other defendants have filed motions to dismiss each of these suits. Oral arguments on the motions were held in April 2003. On

July 14, 2003, the Court dismissed Williams and its Board, but not the members of the Benefits and Investment Committees to whom Williams might have an indemnity obligation. The Department of Labor is also independently investigating Williams' employee benefit plans. A decision in the shareholder suits is pending. Derivative shareholder suits have been filed in state court in Oklahoma, all based on similar allegations. On August 1, 2002, a motion to consolidate and a motion to stay these suits pending action by the federal court in the shareholder suits was approved.

On April 26, 2002, the Oklahoma Department of Securities issued an order initiating an investigation of Williams and WilTel regarding issues associated with the spin-off of WilTel and regarding the WilTel bankruptcy. Williams has committed to cooperate fully in the investigation.

On November 30, 2001, Shell Offshore, Inc. filed a complaint at the FERC against Williams Gas Processing - Gulf Coast Company, L.P. (WGP), Williams Gulf Coast Gathering Company (WGCGC), Williams Field Services Company (WFS) and Transco, alleging concerted actions by the affiliates frustrating the FERC's regulation of Transco. The alleged actions are related to offers of gathering service by WFS and its subsidiaries on the recently spundown and deregulated North Padre Island offshore gathering system. On September 5, 2002, the FERC issued an order reasserting jurisdiction over that portion of the North Padre Island facilities previously transferred to WFS. The FERC also determined an unbundled gathering rate for service on these facilities which is to be collected by Transco. Transco, WGP, WGCGC and WFS believe their actions were reasonable and lawful and sought rehearing of the FERC's order which was denied by the FERC on May 15, 2003. Transco, WGP, WGCGC and WFS have each filed petitions for review of the FERC's orders with the U.S. Court of Appeals for the District of Columbia. They also filed a joint motion to consolidate their appeals which was granted by the Court. These appeals were consolidated on August 25, 2003.

On October 23, 2002, Western Gas Resources, Inc. and its subsidiary, Lance Oil and Gas Company, Inc., filed suit against Williams Production RMT Company in District Court for Sheridan, Wyoming, claiming that the merger of Barrett Resources Corporation and Williams triggered a preferential right to purchase a portion of the coal bed methane development properties owned by Barrett in the Powder River Basin of northeastern Wyoming. In addition, Western claims that the merger triggered certain rights of Western to replace Barrett as operator of those properties. On October 24, 2003, Williams and Western announced the settlement of these claims. The main elements of the settlement allowed Williams to receive improved terms in a long-term gathering agreement with Western in exchange for a subsidiary of Western gaining rights to operate approximately one-half of the properties jointly owned with Williams.

Williams Alaska Petroleum, Inc. (WAPI) is actively engaged in administrative litigation being conducted jointly by the FERC and the Regulatory Commission of Alaska concerning the Trans-Alaska Pipeline System (TAPS) Quality Bank. Primary issues being litigated include the appropriate valuation of the naphtha, heavy distillate, vacuum gas oil and residual product cuts within the TAPS Quality Bank as well as the appropriate retroactive effects of the determinations. WAPI's interest in these proceedings is material as the matter involves claims by crude producers and the State of Alaska for retroactive payments plus interest from WAPI in the range of $50 million to $200 million aggregate. Because of the complexity of the issues involved, however, the outcome cannot be predicted with certainty nor can the likely result be quantified.

Power has paid and received various settlement amounts in conjunction with the liquidation of trading positions during 2002 and the first six months of 2003. One counterparty, American Electric Power Company, Inc. (AEP), disputed a settlement amount related to the liquidation of a trading position with Power that was initially calculated to be in excess of $100 million payable to Power. Arbitration was initiated to resolve this dispute. On June 5, 2003, Power and AEP executed a settlement agreement resolving the dispute, pursuant to which AEP paid Power $90 million. AEP is a related party as a result of a director who serves on both Williams' and AEP's board of directors.

Pursuant to various purchase and sale agreements relating to divested businesses and assets, Williams has indemnified certain purchasers against liabilities that they may incur with respect to the businesses and assets acquired from Williams. The indemnities provided to the purchasers are customary in sale transactions and are contingent upon the purchasers incurring liabilities that are not otherwise recoverable from third parties. The indemnities generally relate to breach of warranties, tax, historic litigation, personal injury, environmental matters, right of way and other representations provided by Williams. At September 30, 2003, Williams does not expect any of the indemnities provided pursuant to the sales agreements to have a material impact on Williams' future financial position. However, if a claim for indemnity is brought against Williams in the future, it may have a material adverse effect on the net income of the period in which the claim is made.

In addition to the foregoing, various other proceedings are pending against Williams or its subsidiaries which are incidental to their operations.

SUMMARY

Litigation, arbitration, regulatory matters and environmental matters are subject to inherent uncertainties. Were an unfavorable ruling to occur, there exists the possibility of a material adverse impact on the net income of the period in which the ruling occurs. Management, including internal counsel, currently believes that the ultimate resolution of the foregoing matters, taken as a whole and after consideration of amounts accrued, insurance coverage, recovery from customers or other indemnification arrangements, will not have a materially adverse effect upon Williams' future financial position.

COMMITMENTS

Power has entered into certain contracts giving it the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are currently in operation throughout the continental United States. At September 30, 2003, Power's estimated committed payments under these contracts are $80 million for the remainder of 2003, range from approximately $391 million to $422 million annually through 2017 and decline over the remaining five years to $57 million in 2022. Total committed payments under these contracts over the next 19 years are approximately $7 billion.

GUARANTEES

In 2001, Williams sold its investment in Ferrellgas Partners L.P. senior common units (Ferrellgas units). As part of the sale, Williams became party to a put agreement whereby the purchaser's lenders can unilaterally require Williams to repurchase the units upon nonpayment by the purchaser of its term loan due to its lender or failure or default by Williams under any of its debt obligations greater than $60 million. The maximum potential obligation under the put agreement at September 30, 2003, was $48.7 million. Williams' contingent obligation decreases as purchaser's payments are made to the lender. Collateral and other recourse provisions include the outstanding Ferrellgas units and a guarantee from Ferrellgas Partners L.P. to cover any shortfall from the sale of the Ferrellgas units at less than face value. The proceeds from the liquidation of the Ferrellgas units combined with the Ferrellgas Partners' guarantee should be sufficient to cover any required payment by Williams. The put agreement expires on December 30, 2005. There have been no events of default and the purchaser has performed as required under payment terms with the lender. No amounts have been accrued for this contingent obligation as management believes it is not probable that Williams would be required to perform under this obligation.

In connection with the 1993 public offering of units in the Williams Coal Seam Gas Royalty Trust (Royalty Trust), Exploration & Production entered a gas purchase contract for the purchase of natural gas in which the Royalty Trust holds a net profits interest. Under this agreement, Exploration & Production guarantees a minimum purchase price that the Royalty Trust will realize in the calculation of its net profits interest. Exploration & Production has an annual option to discontinue this minimum purchase price guarantee and pay solely based on an index price. The maximum potential future exposure associated with this guarantee is not determinable because it is dependent upon natural gas prices and production volumes. No amounts have been accrued for this contingent obligation as the index price continues to exceed the minimum purchase price.

In connection with the 1987 sale of certain real estate assets associated with its Tulsa headquarters, Williams guaranteed 70 percent of the principal and interest payments through 2007 on revenue bonds issued by the purchaser to finance the purchase of those assets. In the event that future operating results from these assets are not sufficient to make the principal and interest payments, Williams is required to fund that short-fall. On July 14, 2003, Williams deposited its 70 percent share ($6.8 million) with the trustee, satisfying its entire remaining obligation.

In connection with the construction of a joint venture pipeline project, Williams guaranteed, through a put agreement, certain portions of the joint venture's project financing in the event of nonpayment by the joint venture. Williams' maximum potential liability under this guarantee, based on the outstanding project financing at September 30, 2003, is $30.8 million. As additional borrowings are made under the project financing facility, Williams' maximum potential exposure will increase. This guarantee expires in March 2005, and no amounts have been accrued at September 30, 2003.

Discovery Pipeline (Discovery) is a joint venture gas gathering and processing system. Williams has provided a guarantee in the event of nonperformance on 50 percent of Discovery's debt obligations, or approximately $126.9 million at September 30, 2003. Performance under the guarantee generally would occur upon a failure of payment by the financed entity or certain events of default related to the guarantor. These events of default primarily relate to bankruptcy and/or insolvency of the guarantor. The guarantee expires upon the maturity of the debt obligation at the end of 2003, and no amounts have been accrued as of September 30, 2003. If ongoing efforts to refinance these obligations are unsuccessful, Williams could be required to perform under its guarantee.

Williams has provided performance guarantees in the event of nonpayment by

WilTel on certain lease performance obligations of WilTel that extend through 2042 and have a maximum potential exposure of approximately $52 million. Williams' exposure declines systematically throughout the remaining term of WilTel's obligations. At September 30, 2003, Williams has an accrued liability of $46.5 million for this guarantee.

Williams has provided guarantees on behalf of certain partnerships in which Williams has an equity ownership interest. These generally guarantee operating performance measures and the maximum potential future exposure cannot be determined. These guarantees continue until Williams withdraws from the partnerships. No amounts have been accrued at September 30, 2003.

Notes (Continued)

12. Stockholders' equity

On June 10, 2003, Williams redeemed all of the outstanding 9 7/8 percent cumulative-convertible preferred shares for approximately $289 million, plus $5.3 million for accrued dividends. These shares were repurchased with proceeds from a private placement of 5.5 percent junior subordinated convertible debentures due 2033 (see Note 10).

13. Comprehensive income (loss)

Comprehensive income (loss) from both continuing and discontinued operations is as follows:

	Three months ended September 30,		Nine months ended September 30,	
(Millions)	2003	2002	2003	2002
Net income (loss)	$ 106.3	$ (294.1)	$ (438.5)	$ (535.5)
Other comprehensive income (loss):				
Unrealized gains (losses) on securities	.5	(.9)	.7	(.1)
Realized gains on securities reclassified into earnings	(13.5)	--	(13.5)	--
Unrealized gains (losses) on derivative instruments	169.4	106.6	(280.8)	(82.3)
Net reclassification into earnings of derivative instrument (gains) losses	(13.3)	(62.9)	10.5	(263.7)
Foreign currency translation adjustments	2.3	(19.5)	55.9	.2
Minimum pension liability adjustment	.2	--	1.8	--
Other comprehensive income (loss) before taxes and minority interest	145.6			

23.3 (225.4) (345.9) Income tax benefit (provision) on other comprehensive loss (54.9) (16.0) 107.5 132.0 ---------- ---------- ---------- ---------- Other comprehensive income (loss) 90.7 7.3 (117.9) (213.9) ---------- ---------- ---------- ---------- Comprehensive income (loss) $ 197.0 $ (286.8) $ (556.4) $ (749.4) ========== ========== ========== ==========

14. Segment disclosures

Segments

Williams' reportable segments are strategic business units that offer different products and services. The segments are managed separately because each segment requires different technology, marketing strategies and industry knowledge. The Petroleum Services segment is now reported within Other as a result of the Alaska refinery and related assets being reflected as discontinued operations. Segment amounts have been restated to reflect this change. Other primarily consists of corporate operations and certain continuing operations previously reported within the International and Petroleum Services segments.

Segments - Performance measurement

Williams currently evaluates performance based upon segment profit (loss) from operations which includes revenues from external and internal customers, operating costs and expenses, depreciation, depletion and amortization, equity earnings (losses) and income (loss) from investments including gains/losses on impairments related to investments accounted for under the equity method. Intersegment sales are generally accounted for as if the sales were to unaffiliated third parties, that is, at current market prices.

Power has entered into intercompany interest rate swaps with the corporate parent, the effect of which is included in Power's segment revenues and segment profit (loss) as shown in the reconciliation within the following tables. The results of interest rate swaps with external counterparties are shown as interest rate swap income (loss) in the Consolidated Statement of Operations below operating income.

The majority of energy commodity hedging by certain Williams' business units is done through intercompany derivatives with Power which, in turn, enters into offsetting derivative contracts with unrelated third parties. Power bears the counterparty performance risks associated with unrelated third parties.

The following tables reflect the reconciliation of revenues and operating income as reported in the Consolidated Statement of Operations to segment revenues and segment profit (loss).

Notes (Continued)

14. Segment disclosures (continued)

(MILLIONS)	Power	Gas Pipeline	Exploration & Production	Midstream Gas & Liquids	Other	Eliminations	Total
THREE MONTHS ENDED SEPTEMBER 30, 2003							
Segment revenues:							
External	$ 3,659.3	$ 312.0	$ (14.6)	$ 835.5	$ 3.1	$ --	$ 4,795.3
Internal	239.1	4.6	183.3	5.5	7.9	(440.4)	--
Total segment revenues	3,898.4	316.6	168.7	841.0	11.0	(440.4)	4,795.3
Less intercompany interest rate swap income	10.0	--	--	--	--	(10.0)	--
Total revenues	$						

3,888.4 $
316.6 $
168.7 $
841.0 $
11.0 $
(430.4) $
4,795.3
=========
==========
===========
==========
=========
============
=========
Segment
profit $
43.9 $
141.4 $
58.8 $ 74.3
$ 4.1 -- $
322.5 Less:
Equity
earnings
(loss) --
6.0 2.5
(1.1) (.6)
-- 6.8
Income from
investments
12.2 -- --
5.4 -- --
17.6
Intercompany
interest
rate swap
income 10.0
-- -- -- --
-- 10.0 ---
------ ----
------ ----
------- ---
------- ---
------ ----
-------- --

Segment
operating
income $
21.7 $
135.4 $
56.3 $ 70.0
$ 4.7 $ --
288.1 -----
---- ------
---- ------
----- -----
----- -----
---- ------
------ ----

General
corporate
expenses
(17.8) ----

Consolidated
operating
income $
270.3
=========
THREE
MONTHS
ENDED
SEPTEMBER
30, 2002
Segment
revenues:
External $
(13.7) $
306.3 $
16.5 $

399.2 $
10.9 $ -- $
719.2
Internal
(276.5)*
17.7 192.9
6.3 15.1
44.5 -- ---
------ ----
------ ----
------- ---
------- ---
------ ----
-------- --

Total
segment
revenues
(290.2)
324.0 209.4
405.5 26.0
44.5 719.2
--------- -
--------- -

--------- -

Less
intercompany
interest
rate swap
loss (71.0)
-- -- -- --
71.0 -- ---
------ ----
------ ----
------- ---
------- ---
------ ----
-------- --

Total
revenues $
(219.2) $
324.0 $
209.4 $
405.5 $
26.0 $
(26.5) $
719.2
=========
==========
===========
==========
=========
============
=========
Segment
profit
(loss) $
(387.6) $
147.2 $
228.2 $
111.6 $
47.4 $ -- $
146.8 Less:
Equity
earnings
(loss) --
11.6 1.5
7.3 (1.3) -
- 19.1
Income
(loss) from
investments
-- (2.7) --
-- 57.8 --
55.1
Intercompany

interest
rate swap
loss (71.0)
-- -- -- --
-- (71.0) -
-------- --
-------- --
--------- -
--------- -
-------- --

Segment
operating
income
(loss) $
(316.6) $
138.3 $
226.7 $
104.3 $
(9.1) $ --
143.6 -----
---- ------
---- ------
----- -----
----- -----
---- ------
------ ----

General
corporate
expenses
(44.1) ----

Consolidated
operating
income $
99.5
=========

- ----------

* Prior to January 1, 2003, Power intercompany cost of sales, which were netted in revenues consistent with fair-value accounting, exceeded intercompany revenue. Beginning January 1, 2003, Power intercompany cost of sales are no longer netted in revenues due to the adoption of EITF Issue No. 02-3 (see Note 3). Segment revenues and profit for Power include net realized and unrealized mark-to-market gains of $95.4 million from derivative contracts accounted for on a fair value basis for the three months ended September 30, 2003.

Notes (Continued)

14. Segment disclosures (continued)

(MILLIONS)	Power	Gas Pipeline	Exploration & Production	Midstream Gas & Liquids	Other	Eliminations	Total
NINE MONTHS ENDED SEPTEMBER 30, 2003							
Segment revenues:							
External	$ 9,904.3	$ 930.3	$ (27.5)	$ 2,448.6	$ 29.2	$ --	$ 13,284.9
Internal	693.2	21.6	640.3	37.0	29.9	(1,422.0)	--
Total segment revenues	10,597.5	951.9	612.8	2,485.6	59.1	(1,422.0)	13,284.9
Less intercompany interest rate swap loss	(12.6)	--	--	--	--	12.6	--

Total
revenues $
10,610.1 $
951.9 $
612.8 $
2,485.6 $
59.1 $
(1,434.6) $
13,284.9 --
-------- --
------- ---
-------- --
-------- --
----- -----
------- ---

Segment
profit
(loss) $
255.5 $
406.5 $
351.3 $
240.1 $
(42.8) $ --
$ 1,210.6
Less:
Equity
earnings
(loss) --
9.8 7.1
(7.1) 2.4 -
- 12.2
Income
(loss) from
investments
12.2 .1 --
1.7 (42.5)
-- (28.5)
Intercompany
interest
rate swap
loss (12.6)
-- -- -- --
-- (12.6) -
--------- -
-------- --
--------- -
--------- -
------ ----
-------- --

Segment
operating
income
(loss) $
255.9 $
396.6 $
344.2 $
245.5 $
(2.7) $ --
1,239.5 ---
------- ---
------ ----
------- ---
------- ---
---- ------
------ ----

General
corporate
expenses
(62.5) ----

Consolidated
operating
income $
1,177.0
============
NINE MONTHS
ENDED
SEPTEMBER

30, 2002
Segment
revenues:
External $
571.5 $
871.5 $
58.4 $
1,060.1 $
33.0 $ -- $
2,594.5
Internal
(785.3)*
48.0 593.8
36.3 45.7
61.5 -- ---
------- ---
------ ----
------- ---
------- ---
---- ------
------ ----

Total
segment
revenues
(213.8)
919.5 652.2
1,096.4
78.7 61.5
2,594.5 ---
------- ---
------ ----
------- ---
------- ---
---- ------
------ ----

Less
intercompany
interest
rate swap
loss
(139.9) --
-- -- --
139.9 -- --
-------- --
------- ---
-------- --
-------- --
----- -----
------- ---

Total
revenues $
(73.9) $
919.5 $
652.2 $
1,096.4 $
78.7 $
(78.4) $
2,594.5
==========
=========
===========
==========
=======
============
============
Segment
profit
(loss) $
(602.0) $
423.0 $
427.1 $
210.2 $
34.9 $ -- $
493.2 Less:
Equity
earnings
(loss)
(4.0) 82.8

2.1 12.5
(13.4) --
80.0 Income
(loss) from
investments
-- (15.0) -
- -- 57.8 -
- 42.8
Intercompany
interest
rate swap
loss
(139.9) --
-- -- -- --
(139.9) ---
------- ---
------ ----
------- ---
------- ---
---- ------
------ ----

Segment
operating
income
(loss) $
(458.1) $
355.2 $
425.0 $
197.7 $
(9.5) $ --
510.3 -----
----- -----
---- ------
----- -----
----- -----
-- --------
---- ------

General
corporate
expenses
(116.4) ---

Consolidated
operating
income $
393.9
============

- ----------

* Prior to January 1, 2003, Power intercompany cost of sales, which were netted in revenues consistent with fair-value accounting, exceeded intercompany revenue. Beginning January 1, 2003, Power intercompany cost of sales are no longer netted in revenues due to the adoption of EITF Issue No. 02-3 (see Note 3). Segment revenues and profit for Power include net realized and unrealized mark-to-market gains of $304.3 million from derivative contracts accounted for on a fair value basis for the nine months ended September 30, 2003.

14. Segment disclosures (continued)

Total Assets (Millions)	September 30, 2003	December 31, 2002
Power	$ 10,091.0	$ 12,532.9
Gas Pipeline	6,953.5	6,892.1
Exploration & Production	5,263.2	5,595.1
Midstream Gas & Liquids	5,135.3	4,736.3
Other	8,371.7	7,664.3
Eliminations	(5,942.4)	(6,636.9)
	29,872.3	30,783.8
Discontinued operations	429.4	4,204.7
Total	$ 30,301.7	$ 34,988.5

15. Recent accounting standards

In January, 2003, the Financial Accounting Standards Board (FASB) issued Interpretation No. 46, "Consolidation of Variable Interest Entities." The Interpretation defines a variable interest entity (VIE) as an entity in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated financial support from other parties. The investments or other interests that will absorb portions of the VIE's expected losses if they occur or receive portions of the VIE's expected residual returns if they occur are called variable interests. Variable interests may include, but are not limited to, equity interests, debt instruments, beneficial interests, derivative instruments and guarantees. The Interpretation requires an entity to consolidate a VIE if that entity will absorb a majority of the VIE's expected losses if they occur, receive a majority of the VIE's expected residual returns if they occur, or both. If no party will absorb a majority of the expected losses or expected residual returns, no party will consolidate the VIE. The Interpretation also requires disclosure of significant variable interests in unconsolidated VIE's. The Interpretation is effective for all new variable interest entities created or acquired after January 31, 2003. For variable interest entities created or acquired prior to February 1, 2003, the provisions of the Interpretation were initially to be effective for the first interim or annual period beginning after June 15, 2003. However, in October 2003, the FASB delayed the effective date of the Interpretation on those entities to the first period ending after December 15, 2003. The effect of the adoption of the Interpretation is not expected to be material to the consolidated financial statements.

EITF Issue No. 01-8, "Determining Whether An Arrangement Contains a Lease", became effective on July 1, 2003, and provides guidance for determining whether certain contracts such as transportation, storage, load serving, and tolling agreements are executory service arrangements or leases pursuant to SFAS No. 13. A prospective transition is provided for whereby the consensus is to be applied to arrangements consummated or modified after July 1, 2003. Williams' initial review indicates that certain of Power's tolling agreements could be considered leases under the consensus if the tolling agreements are modified after July 1, 2003. If such tolling agreements are deemed to be capital leases, the net present value of the demand payments would be reported on the balance sheet consistent with debt as an obligation under capital lease, and as an asset in property, plant and equipment.

ITEM 2
MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

RECENT EVENTS AND COMPANY OUTLOOK

On February 20, 2003, Williams outlined its planned business strategy for the next few years. Williams believes it to be a comprehensive response to the events that have impacted the energy sector and Williams during 2002. The plan focuses on retaining a strong, but smaller, portfolio of natural gas businesses and bolstering Williams' liquidity through additional asset sales, strategic levels of financing at the Williams and subsidiary levels and additional reductions in operating costs. The plan is designed to provide Williams with a clear strategy to address near-term and medium-term liquidity issues and further de-leverage the company with the objective of returning to investment grade status and developing a balance sheet capable of supporting retained businesses with favorable returns and opportunities for growth in the future.

During second-quarter 2003, Williams repaid the RMT note payable of approximately $1.15 billion (including certain contractual fees and deferred interest) which was due in July 2003. A portion of the RMT note payable was refinanced by the issuance of $500 million secured, subsidiary-level financing at a floating rate equal to the six-month London Interbank Offered Rate (LIBOR) plus 3.75 percent (totaling 4.9 percent at September 30, 2003). Also during second-quarter 2003, Williams issued $800 million of 8.625 percent senior unsecured notes due 2010. Williams intends to use the net proceeds from the $800 million offering to improve corporate liquidity, for general corporate purposes, and for payment of maturing debt obligations, including of the Company's senior unsecured 9.25 percent notes due March 2004.

Also in second-quarter 2003, Williams issued $300 million of 5.5 percent junior subordinated convertible debentures due 2033 and utilized the proceeds to redeem all of the outstanding 9 7/8 percent cumulative convertible preferred stock for approximately $289 million, plus $5.3 million for accrued dividends. The new convertible debentures provide Williams with more favorable terms that, on an annual basis, result in approximately $17 million in lower after-tax carrying costs compared with the convertible preferred shares. Williams also obtained a new $800 million revolving credit facility that is collateralized by purchased government securities and/or cash and will be utilized mainly for issuance of letters of credit. This new facility enabled the release of the midstream assets that served as security for the previous credit facilities.

At September 30, 2003, Williams has notes payable and long-term debt maturing through the first quarter of 2004 totaling approximately $1.6 billion. The maturing notes and long-term debt are expected to be repaid with cash on hand, proceeds from asset sales and cash flows from operations.

In the third quarter of 2003, Williams' Board of Directors authorized the Company to retire or otherwise prepay up to $1.8 billion of debt, including $1.4 billion designated for the Company's 9.25% notes due on March 15, 2004. On October 8, 2003, the Company announced a cash tender offer for any and all of Williams' $1.4 billion senior unsecured 9.25 percent notes due March 2004 as well as cash tender offers and consent solicitations for $241 million of additional outstanding notes and debentures. As of October 31, 2003, approximately $720 million of the 9.25 percent notes had been accepted for purchase. Additionally, Williams received tenders of notes and deliveries of related consents from holders of approximately $230 million of the other notes and debentures. The tender offers are scheduled to expire on November 6, 2003. The Company will use available cash to fund the purchase of any notes accepted under the tender offers.

Long-term debt, excluding the current portion, at September 30, 2003 was approximately $11 billion. See the Liquidity section for a maturity schedule of the Company's long-term debt.

As part of its planned business strategy, Williams expects to generate proceeds, net of related debt, of approximately $4 billion during 2003 and 2004 primarily from asset sales, as well as the contribution of proceeds from the sale and/or termination of certain contracts within its marketing and trading portfolio. Through September 30, 2003, Williams received approximately $3.1 billion in net proceeds from the sale of assets, businesses and the sale and/or termination of certain marketing and trading contracts. Of this amount, $2.8 billion was realized from the sale of assets and businesses, including the following:

o retail travel centers;

o Midsouth refinery;

- bio-energy operations;

- Texas Gas Transmission Corporation;

- general partnership interest and limited partner investment in Williams Energy Partners;

- certain natural gas exploration and production properties in Kansas, Colorado, New Mexico and Utah;

- Colorado soda ash mining operations; and

- certain gas processing, natural gas liquids fractionation, gathering and storage operations in western Canada and at a plant in Redwater, Alberta.

The additional assets and/or businesses expected to be sold in 2003 and 2004 include the Alaska refinery and related assets, and certain assets within Midstream Gas & Liquids (Midstream). The specific assets and the timing of such sales are dependent on various factors, including negotiations with prospective buyers, regulatory approvals, industry conditions, and Williams' short- and long-term liquidity requirements. While management believes it has considered all relevant information in assessing potential impairments, the ultimate sales price for assets that may be sold and the final decisions in the future may result in additional impairments or losses and/or gains.

During third-quarter 2003, Williams announced the name change of Williams Energy Marketing & Trading to Williams Power Company, Inc. (Power). Williams' management believes the new name more accurately reflects the segment's current business activity. Williams continues its efforts to reduce its commitment to Power activities and exit this business. As part of these efforts, Power has focused on managing its existing contractual commitments, while pursuing potential dispositions and restructuring of certain of its long-term contracts. Through September 30, 2003, Power has sold contracts resulting in cash proceeds of approximately $315 million, which is included in the $3.1 billion of total proceeds discussed above. Although management currently believes that the Company has the financial resources and liquidity to meet the expected cash requirements of Power, the Company continues to pursue several specific transactions with interested parties involving the sales of portions of Power's portfolio and would consider the sale or joint venture of all of the portfolio.

The Company's available liquidity to meet maturing debt requirements and fund a reduced level of capital expenditures will be dependent on several factors, including available cash on hand, the cash flows of retained businesses, the amount of proceeds raised from the sale of assets previously mentioned, the price of natural gas, and capital spending. Future cash flows from operations may also be affected by the timing and nature of the sale of assets. Because of completed and anticipated asset sales, cash on hand, potential external financings, and available secured credit facilities, Williams currently believes that it has, or has access to, the financial resources and liquidity to meet future cash requirements.

GENERAL

In accordance with the provisions related to discontinued operations within Statement of Financial Accounting Standard (SFAS) No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," the consolidated financial statements and notes in Item 1 reflect the results of operations, financial position and cash flows through the date of sale, as applicable, of the following components as discontinued operations (see Note 6):

- Kern River Gas Transmission (Kern River), previously one of Gas Pipeline's segments;
- Central natural gas pipeline, previously one of Gas Pipeline's segments;
- Texas Gas Transmission Corporation, previously one of Gas Pipeline's segments;
- natural gas properties in the Hugoton and Raton basins, previously part of the Exploration & Production segment;
- two natural gas liquids pipeline systems, Mid-American Pipeline and Seminole Pipeline, previously part of the Midstream segment;
- Gulf Liquids New River Project LLC, previously part of the Midstream segment;
- refining and marketing operations in the Midsouth, including the Midsouth refinery, part of the previously reported Petroleum Services segment;
- retail travel centers concentrated in the Midsouth, part of the previously reported Petroleum Services segment;
- bio-energy operations, part of the previously reported Petroleum Services segment;
- refining, retail and pipeline operations in Alaska, part of the previously reported Petroleum Services segment;
- Williams' general partnership interest and limited partner investment in Williams Energy Partners, previously the Williams Energy Partners segment;

- Colorado soda ash mining operations, part of the previously reported International segment;

- certain gas processing, natural gas liquids fractionation, storage and distribution operations in western Canada and at a plant in Redwater, Alberta, previously part of the Midstream segment.

Management's Discussion & Analysis (Continued)

Unless indicated otherwise, the following discussion and analysis of results of operations, financial condition and liquidity relates to the current continuing operations of Williams and should be read in conjunction with the consolidated financial statements and notes thereto included in Item 1 of this document and Williams' 2002 Annual Report on Form 10-K.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

As noted in the 2002 Annual Report on Form 10-K, Williams' financial statements reflect the selection and application of accounting policies that require management to make significant estimates and assumptions. One of the critical judgment areas in the application of our accounting policies noted in the Form 10-K is the revenue recognition of energy risk management and trading operations. As a result of the application of the conclusions reached by the Emerging Issues Task Force in Issue No. 02-3, "Issues related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities," (EITF 02-3) the methodology for revenue recognition related to energy risk management and trading activities changed January 1, 2003. Williams initially applied the consensus effective January 1, 2003 and reported the initial application as a cumulative effect of a change in accounting principle. See Note 3 for a discussion of the impacts on Williams' financial statements as a result of applying this consensus.

RESULTS OF OPERATIONS

Consolidated Overview

The following table and discussion is a summary of Williams' consolidated results of operations. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

	THREE MONTHS ENDED SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2003	2002	2003	2002
	(MILLIONS)			
Revenues	$ 4,795.3	$ 719.2	$ 13,284.9	$ 2,594.5
Costs and expenses:				
Costs and operating expenses	4,434.7	527.3	11,973.1	1,594.4
Selling, general and administrative expenses	97.3	158.1	321.6	452.7
Other (income) expense-net	(24.8)	(109.8)	(249.3)	37.1
General corporate expenses	17.8	44.1	62.5	

116.4 -------
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----- Total
costs and
expenses
4,525.0 619.7
12,107.9
2,200.6
Operating
income 270.3
99.5 1,177.0
393.9
Interest
accrued-net
(264.9)
(334.3)
(1,000.5)
(780.9)
Interest rate
swap income
(loss) 2.5
(52.2) (6.4)
(125.2)
Investing
income (loss)
40.6 55.3
43.8 (122.9)
Minority
interest in
income and
preferred
returns of
consolidated
subsidiaries
(5.6) (12.2)
(15.1) (35.7)
Other income-
net 3.7 .5
39.7 19.0 ---
--------- ---
--------- ---
--------- ---

Income (loss)
from
continuing
operations
before income
taxes and
cumulative
effect of
change in
accounting
principles
46.6 (243.4)
238.5 (651.8)
Provision
(benefit) for
income taxes
23.8 (72.2)
138.8 (191.3)

Income (loss)
from
continuing
operations
22.8 (171.2)
99.7 (460.5)
Income (loss)
from
discontinued
operations
83.5 (122.9)
223.1 (75.0)

Income (loss)
before
cumulative
effect of
change in
accounting
principles
106.3 (294.1)
322.8 (535.5)
Cumulative
effect of
change in
accounting
principles --
-- (761.3) --

Net income
(loss) 106.3
(294.1)
(438.5)
(535.5)
Preferred
stock
dividends --
6.8 29.5 83.3

Income (loss)
applicable to
common stock
$ 106.3 $
(300.9) $
(468.0) $
(618.8)
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Three Months Ended September 30, 2003 vs. Three Months Ended September 30, 2002

Williams' revenue increased $4.1 billion due primarily to increased revenues at Power and Midstream as a result of the adoption of EITF 02-3, which requires that revenues and cost of sales from non-derivative contracts and certain physically settled derivative contracts be reported on a gross basis. As permitted by EITF 02-3, prior year amounts have not been restated. Prior to the adoption of EITF 02-3 on January 1, 2003, revenues and costs of sales related to non-derivative contracts and certain physically settled derivative contracts were reported in revenues on a net basis. Power's revenues increased $4.2 billion and Midstream revenues increased $436 million. Offsetting these revenue increases at the operating units was $485 million higher intercompany eliminations primarily resulting from intercompany costs that were previously netted in revenues prior to the adoption of EITF 02-3.

Costs and operating expenses increased $3.9 billion due primarily to the impact of reporting certain costs gross at Power and Midstream, as discussed above. Costs and operating expenses increased $3.8 billion at Power and $478 million at Midstream. Contributing to the increase at Midstream is a $94 million increase attributable to higher market prices for natural gas. Offsetting these cost increases at the operating units was $485 million higher intercompany eliminations primarily as a result of intercompany costs that were previously netted in revenues prior to the adoption of EITF 02-3.

Selling, general and administrative expenses decreased $60.8 million due primarily to employee reductions at Power and, to a lesser extent, Gas Pipeline, which resulted in lower salaries, benefits and other related costs.

Other (income) expense - net in 2002 reflects a $143.9 million gain from the sale of Exploration & Production's interests in natural gas properties.

General corporate expenses decreased $26.3 million, or 60 percent, due primarily to the absence of $20 million of costs related to consulting services and legal fees associated with the liquidity and business issues addressed during third-quarter 2002.

Operating income (loss) improved by $170.8 million due primarily to a $338.3 million favorable change in operating income (loss) at Power and a $26.3 million decrease in general corporate expenses. The increase in operating income (loss) is partially offset by a $170.4 million decrease in operating income at Exploration & Production and a $34.3 million decrease at Midstream. The decrease at Exploration & Production is due primarily to the absence in 2003 of $143.9 million in gains on sales of natural gas production properties in Wyoming and the Anadarko basin during third-quarter 2002.

Interest accrued - net decreased $69.4 million, or 21 percent, due primarily to the absence in 2003 of $59.9 million of interest expense and fees on the RMT note payable, which was repaid in May 2003 (see Note 10), and $8 million lower amortization expense related to deferred debt issuance costs, partially offset by $10 million higher interest expense related to a petroleum pricing dispute. An additional $7 million decrease in interest expense is attributable to a $2 million decrease reflecting lower average borrowing levels of long-term debt in 2003 and a $5 million decrease reflecting lower average interest rates on long-term debt in 2003.

In 2002, Williams began entering into interest rate swaps with external counter parties primarily in support of the energy-trading portfolio (see Note 14). The change in market value of these swaps was $54.7 million more favorable in 2003 than 2002. The total notional amount of these swaps is approximately $300 million at September 30, 2003 as compared to approximately $450 million at September 30, 2002.

Investing income (loss) for the three months ended September 30, 2003 and 2002 consisted of the following components:

	THREE MONTHS ENDED SEPTEMBER 30,	
	2003	2002
	(MILLIONS)	
Equity earnings*	$ 6.8	$ 19.1
Loss provision for WCG receivables	--	(22.9)
Income (loss) from investments*:		
Gain on sale of equity interest in Northern Border Partners, L.P.	--	8.7
Gain on sale of marketable equity securities	13.5	--
Gain on sale of West Texas Pipeline	11.0	--
Gain on sale of investment in AB Mazeikiu Nafta	--	58.5
Net write-down of investment in Alliance Pipeline	--	(11.6)
Impairment of investment in Aux Sable	(5.6)	--
Other investments	(1.3)	(.5)
Impairment of cost based investments	(3.5)	(9.3)
Interest income and other	19.7	13.3
Investing income (loss)	$ 40.6	$ 55.3

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* These items are also included in the measure of segment profit (loss).

The decline in equity earnings for the three months ended September 30, 2003 as compared to 2002 is partially attributable to $6 million lower equity earnings following the October 2002 sale of Gas Pipeline's 14.6 percent ownership in Alliance Pipeline. The $22.9 million loss provision in 2002 is related to the estimated recoverability of receivables from WilTel Communications Group, Inc. (formerly Williams Communications Group, Inc.) (WilTel). In 2002, the $58.5 million gain on sale relates to the investment in a Lithuanian oil refinery, pipeline and terminal complex and the $11.6 million net write-down relates to Williams' equity interest in a Canadian and U.S. gas pipeline. In 2003, the $13.5 million gain relates to the sale of stock in eSpeed Inc., and the $11 million gain reflects the sale of a 20 percent aggregate ownership interest in the 3,000-mile West Texas LPG Pipeline Limited Partnership. Interest income and other increased $6.4 million due primarily to approximately $7 million of interest income on the WilTel promissory notes relating to the 2002 sale of the Technology Center.

Minority interest in income and preferred returns of consolidated subsidiaries in 2003 is lower than 2002 due primarily to the absence in 2003 of preferred returns totaling $9 million on the preferred interests in Castle Associates L.P., Piceance Production Holdings L.L.C., and Williams' Risk Holdings L.L.C., which were reclassified as debt in the third quarter of 2002, and Arctic Fox, L.L.C., which was reclassified as debt in April 2002.

The change in provision (benefit) for income taxes was unfavorable by $96.0 million due primarily to pre-tax income in 2003 as compared to a pre-tax loss for 2002. The effective income tax rate for the three months ended September 30, 2003, is greater than the federal statutory rate due primarily to foreign operations and state income taxes. The effective income tax rate for the three months ended September 30, 2002 is less than the federal statutory rate due primarily to foreign operations which reduce the tax benefit of the pretax loss.

The decrease in preferred stock dividends reflects the June 10, 2003 redemption of all the outstanding 9 7/8 percent cumulative-convertible preferred shares (see Note 12).

Nine Months Ended September 30, 2003 vs. Nine Months Ended September 30, 2002

Williams' revenue increased $10.7 billion due primarily to increased revenues at Power and Midstream as a result of the adoption of EITF 02-3, which requires that revenues and cost of sales from non-derivative contracts and certain physically settled derivative contracts be reported on a gross basis. As permitted by EITF 02-3, prior year amounts have not been restated. Prior to the adoption of EITF 02-3 on January 1, 2003, revenues and costs of sales related to non-derivative contracts and certain physically settled derivative contracts were reported in revenues on a net basis. Power's revenues increased $10.8 billion and Midstream's revenues increased $1.4 billion. The increase in revenues includes $327 million higher revenues at Midstream primarily resulting from higher natural gas liquids (NGL) revenues at gas processing plants caused by higher NGL prices in both domestic and Canadian markets and significantly higher volumes produced at the Canadian facilities. Partially offsetting these revenue increases at the operating units was $1.4 billion higher intercompany eliminations primarily resulting from intercompany costs that were previously netted in revenues prior to the adoption of EITF 02-3. During the second quarter of 2003, Power corrected the accounting treatment previously applied to certain third party derivative contracts during 2002 and 2001, resulting in the recognition of $80.7 million in revenues in the second quarter of 2003 attributable to prior periods (see Note 1). These corrections relate to the fair value of these derivative contracts and do not represent current period actual cash flows.

Costs and operating expenses increased $10.4 billion due primarily to the impact of reporting certain costs gross at Power and Midstream, as discussed above. Costs and operating expenses increased $10.4 billion at Power and $1.3 billion at Midstream. Contributing to the increase at Midstream is a $227 million increase due to higher market prices for natural gas used to replace the heating value of NGL's extracted at Midstream's gas processing facilities. Offsetting these cost increases at the operating units was $1.4 billion higher intercompany eliminations primarily as a result of intercompany costs that were previously netted in revenues prior to the adoption of EITF 02-3.

Selling, general and administrative expenses decreased $131.1 million due primarily to reduced employee levels at Power and, to a lesser extent, Gas Pipeline, and the absence of $21 million of costs related to an enhanced benefit early retirement option offered to certain employee groups in 2002.

Other (income) expense - net in 2003 reflects a $188 million gain from the sale of a Power contract and $96.4 million in net gains from the sale of Exploration & Production's interests in natural gas properties. Partially offsetting these gains was a $25.5 million charge at Northwest Pipeline to write-off capitalized software development costs for a service delivery system following a decision not to implement that system and a $20 million charge related to a settlement by Power with the Commodity Futures Trading Commission (see Note 11). Other (income) expense - net in 2002 includes $152.7 million of impairment charges, loss accruals, and write-offs within Power, including a partial impairment of goodwill, and $143.9 million in net gains from the sale of Exploration & Production's interests in natural gas properties.

General corporate expenses decreased $53.9 million, or 46 percent, due primarily to the absence of $24 million of costs related to consulting services and legal fees associated with the liquidity and business issues addressed during third-quarter 2002 and $16.5 million lower advertising and branding costs.

Operating income increased $783.1 million due primarily to a $714.0 million improvement at Power, a $47.8 million increase at Midstream primarily from domestic gathering and processing operations and $53.9 million lower general corporate expenses. The increase in operating income (loss) is partially offset by $48 million lower net gains in 2003 on the sale of Exploration & Production's interests in natural gas properties.

Interest accrued - net increased $219.6 million, or 28 percent, due primarily to $149.5 million of interest expense and fees on the RMT note payable, which was repaid in May 2003 (see Note 10), $26.1 million higher amortization expense related to deferred debt issuance costs, $12 million of interest expense within Power related to a FERC ruling and $10 million of interest expense related to a pending petroleum pricing dispute. Interest accrued - net increased by an additional $32 million due to a $43 million increase reflecting higher average interest rates on long-term debt in 2003, offset slightly by an $11 million decrease reflecting lower average borrowing levels. The $26.1 million higher amortization expense related to deferred debt issuance costs primarily reflects $14.5 million in accelerated amortization of costs related to the termination of the revolving credit agreement that was replaced in June 2003 (see Note 10). These increases were slightly offset by an $18.5 million increase in capitalized interest at Midstream due primarily to projects in the Gulf Coast region.

In 2002, Williams began entering into interest rate swaps with external counter parties primarily in support of the energy-trading portfolio (see Note 14). The market value of these swaps was $118.8 million more favorable in 2003 than 2002. The total notional amount of these swaps is approximately $300 million at September 30, 2003 as compared to approximately $450 million at September 30, 2002.

Investing income (loss) for the nine months ended September 30, 2003 and 2002 consisted of the following components:

	NINE MONTHS ENDED SEPTEMBER 30,	
	2003	2002
	(MILLIONS)	
Equity earnings*	$ 12.2	$ 80.0
Loss provision for WCG receivables	--	(269.9)
Income (loss) from investments*:		
Gain on sale of equity interest in Northern Border Partners, L.P.	--	8.7
Gain on sale of marketable equity securities	13.5	--
Gain on sale of West Texas Pipeline	11.0	--
Gain on sale of investment in AB Mazeikiu Nafta	--	58.5
Net write-down of investment in Alliance Pipeline	--	(11.6)
Impairment investment in Aux Sable	(14.1)	--
Impairment of investment in Independence Pipeline	--	(12.3)
Impairment of investment in Longhorn Partners Pipeline L.P.	(42.4)	--
Other investments	3.5	(.5)
Impairment of cost		

based investments (34.6) (12.4)
Interest income and other 94.7 36.6 ------------ ------------
Investing income (loss) $ 43.8 $ (122.9)
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* These items are also included in the measure of segment profit (loss).

Equity earnings decreased $67.8 million due primarily to $27 million lower equity earnings from Gulfstream Natural Gas System, LLC (Gulfstream) and the absence of a $27.4 million benefit in 2002 related to the contractual construction completion fee received by an equity affiliate that served as the general contractor on the Gulfstream project and the absence of $17 million of equity earnings following the October 2002 sale of Gas Pipeline's 14.6 percent ownership interest in Alliance Pipeline. The $269.9 million loss provision in 2002 was related to the estimated recoverability of receivables from WilTel. In 2002, the $58.5 million gain on sale relates to the investment in a Lithuanian oil refinery, pipeline and terminal complex and the $11.6 million net write-down relates to Williams' equity interest in a Canadian and U.S. gas pipeline. The $42.4 million impairment in 2003 relates to the investment in equity and debt securities of Longhorn Partners Pipeline LP (Longhorn). Also in 2003, the $13.5 million gain relates to the sale of stock in eSpeed Inc., and the $11 million gain reflects the sale of a 20 percent aggregate ownership interest in the 3,000-mile West Texas LPG Pipeline Limited Partnership. Impairment of cost based investments in 2003 includes a $13.2 million impairment of Algar Telecom S.A. (Algar), a $13.5 million impairment of ReserveCo and a $7.9 million impairment of various international investments. Each of these impairments results from management's determination that there was an other than temporary decline in the estimated fair value of each investment. Interest income and other increased $58.1 million due primarily to a $36.2 million increase at Power comprised primarily of interest income as a result of certain 2003 FERC proceedings. Also contributing to the increase in interest income is $15 million of interest income on the WilTel promissory notes relating to the 2002 sale of the Technology Center, $4 million higher interest income due primarily to higher cash and cash equivalents balances, a $4 million increase in interest income from advances to equity affiliates and a $4 million increase in interest from margin deposits.

Minority interest in income and preferred returns of consolidated subsidiaries in 2003 is lower than 2002 due primarily to the absence of preferred returns totaling $23.5 million on the preferred interests in Castle Associates L.P., Piceance Production Holdings L.L.C., and Williams' Risk Holdings L.L.C., which were reclassified as debt in third-quarter 2002, and Arctic Fox, L.L.C., which was reclassified as debt in April 2002.

Other income - net in 2003 includes $69.2 million of foreign currency transaction gains on a Canadian dollar denominated note receivable partially offset by $55.3 million of derivative losses on a forward contract to fix the U.S. dollar principal cash flows from this note. Other income - net in 2002 includes an $11 million gain at Gas Pipeline associated with the disposition of securities received through a mutual insurance company reorganization offset by a $8 million loss related to early retirement of remarketable notes.

The change in provision (benefit) for income taxes was unfavorable by $330.1 million due primarily to pre-tax income in 2003 as compared to a pre-tax loss for 2002. The effective income tax rate for the nine months ended September 30, 2003, is greater than the federal statutory rate due primarily to nondeductible expenses, state income taxes, foreign operations, the financial impairment of certain investments and capital losses generated for which valuation allowances were established. The effective income tax rate for the nine months ended September 30, 2002 is less than the federal statutory rate due primarily to the impairment of goodwill which is not deductible for income tax purposes and foreign operations which reduce the tax benefit of the pre-tax loss.

The cumulative effect of change in accounting principles reduced net income for 2003 by $761.3 million due to a $762.5 million charge related to the adoption of EITF 02-3 (see Note 3), slightly offset by $1.2 million related to the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations" (see Note 3).

Preferred stock dividends in 2002 reflects the first-quarter 2002 impact of recording a $69.4 million noncash dividend associated with the accounting for a preferred security that contained a conversion option that was beneficial to the purchaser at the time the security was issued.

RESULTS OF OPERATIONS - SEGMENTS

Williams is currently organized into the following segments: Power, Gas Pipeline, Exploration & Production, and Midstream. Due to recent asset sales and the approval of additional asset sales, Williams Energy Partners and Petroleum Services are no longer reportable segments as most of the operations comprising these segments are now reported in discontinued operations. Williams currently evaluates performance based upon several measures including segment profit (loss) from operations (see Note 14). Segment profit of the operating companies may vary by quarter. The following discussions relate to the results of operations of Williams' segments.

POWER

	THREE MONTHS ENDED SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2003	2002	2003	2002
	(MILLIONS)			
Segment revenues	$ 3,898.4	$ (290.2)	$ 10,597.5	$ (213.8)
Segment profit	$ 43.9	$ (387.6)	$ 255.5	$ (602.0)

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Three Months Ended September 30, 2003 vs. Three Months Ended September 30, 2002

POWER'S revenues and cost of sales increased by $4.2 billion and $3.8 billion, respectively, which equates to an increase in gross margin of $358 million. This significant increase in revenues and cost of sales is primarily a result of the adoption of EITF 02-3, which requires that revenues and cost of sales from non-derivative energy contracts and certain physically settled derivative contracts be reported on a gross basis. Prior to the adoption of EITF 02-3 on January 1, 2003, revenues related to non-derivative energy contracts were reported on a net basis in trading revenues. EITF 02-3 does not require prior year amounts to be restated.

On October 25, 2002, the EITF concluded on Issue No. 02-3, which rescinded Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities", under which all energy trading contracts, derivative and non-derivative, were required to be valued at fair value with the net change in fair value of these contracts representing unrealized gains and losses reported in income currently and recorded as revenues in the Consolidated Statement of Operations. Energy contracts include forward contracts, futures contracts, options contracts, swap agreements, commodity inventories, short- and long-term purchase and sale commitments, which involve physical delivery of an energy commodity and energy-related contracts, such as transportation, storage, full requirements, load serving and power tolling contracts. Energy-related contracts that are not considered to be derivatives under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" are no longer presented on the balance sheet at fair value. These contracts are now reported under the accrual method of accounting. In addition, trading inventories are no longer marked to market but are reported on a lower of cost or market basis. Upon adoption of this new standard on January 1, 2003, Power recorded an adjustment as a cumulative effect of change in accounting principle to remove the previously reported fair value of non-derivative energy contracts from the balance sheet. Power's portion of this change in accounting principle was approximately $755 million on an after-tax basis (see Note 3) and was recognized in first-quarter 2003.

Power's gross margin increased $358 million principally due to a $351.5 million higher power and natural gas gross margin, $26.1 million higher petroleum products gross margin, and $7 million higher European gross margin, slightly offset by $26.7 million lower emerging products gross margin.

The power and natural gas gross margin increased $351.5 million from a margin loss of $320.1 million in 2002 to a $31.4 million gross margin in 2003. The $31.4 million gross margin in 2003 is primarily comprised of a $33.6 million accrual loss and a $65 million mark-to-market gain. The accrual loss of $33.6 million is primarily related to narrower margins between power sales prices less the cost of gas and power conversion services, or "spark spreads," on the tolling portfolio that do not exceed contractually-obligated capacity payments. The $65 million mark-to-market gain includes a $126.8 million valuation increase to a derivative contract based on the terms of an agreement to terminate the contract, partially offset by mark-to-market losses primarily resulting from decreased gas prices on long natural gas positions. In 2002, all energy-related trading contracts, including tolling and full requirements contracts, were marked to market. In 2003, with the implementation of EITF 02-3 as discussed above, these non-derivative energy-related trading contracts were accounted for on an accrual basis. Therefore, 2002 earnings reflect the unfavorable impact of narrower spark spreads in future periods on certain power tolling portfolios and a valuation adjustment of $74.8 million as a result of market information obtained through sales efforts on certain full requirements contracts. In contrast, in 2003, the earnings for these types of non-derivative contracts are reported on an accrual basis. Therefore, any forward gains or losses resulting from changes in fair value are excluded from current earnings for non-derivative contracts, whereas the changes in the forward value of certain derivatives contracts continue to be included in earnings.

The petroleum products portfolio gross margin improved from a gross margin loss of $42.4 million in 2002 to a gross margin loss of $16.3 million in 2003. The $16.3 million gross margin loss in 2003 is primarily comprised of a $9.9 million accrual loss and a $6.4 million mark-to-market loss. This $26.1 million improvement in gross margin was impacted by the implementation of EITF 02-3. The petroleum products portfolio was adversely affected in 2002 by a decrease in the fair value of refined products storage and transportation portfolios. In third-quarter 2003, however, these non-derivative contracts were accounted for on an accrual basis and accordingly earnings do not reflect changes in fair value.

The European gross margin improved from $1.5 million in 2002 to $8.5 million in 2003. This $7 million increase in European gross margin is primarily attributable to lower losses in 2003 as European operations have been substantially eliminated. The emerging products gross margin decreased from $63.6 million in 2002 to a $36.9 million mark-to-market gain in 2003. The $26.7 million decrease in emerging products gross margin is primarily attributable to lower interest rates on forward interest rate positions that are marked to market.

Selling, general, and administrative expenses decreased by $39 million, or 60 percent. This cost reduction is primarily due to the impact of employee reductions in the Power business segment. Power employed approximately 251 employees at September 30, 2003, compared with approximately 582 employees at September 30, 2002.

Other (income) expense - net increased $35.3 million. This increase is due primarily to a $13.5 million gain from the sale of Power's investment in eSpeed common stock, receipt of $13 million in contingent sales proceeds in connection with an energy trading contract sold in the second quarter of 2003 and the effect in 2002 of a $11.5 million write-off associated with a terminated power plant project.

Segment profit increased $431.5 million due primarily to increased power, natural gas, petroleum products and European gross margins, decreased selling, general and administrative expenses and improved other (income) expense - net, partially offset by decreased emerging products gross margin as discussed above.

Power's future results will continue to be affected by the willingness of counterparties to enter into transactions with Power, the liquidity of markets in which Power operates, and the creditworthiness of other counterparties in the industry and their ability to perform under contractual obligations. Because Williams is not currently rated investment grade by credit rating agencies, Williams is required, in certain instances, to provide additional adequate assurances in the form of cash or credit support to enter into and maintain existing transactions. The financial and credit constraints of Williams will likely continue to result in Power having exposure to market movements, which could result in future operating losses. In addition, other companies in the energy trading and marketing sector are experiencing financial difficulties which will affect Power's credit and default assessment related to the future value of its forward positions and the ability of such counterparties to perform under contractual obligations. The ultimate outcome of these items could result in future operating losses for Power or limit Power's ability to achieve profitable operations.

Nine Months Ended September 30, 2003 vs. Nine Months Ended September 30, 2002

POWER'S revenues and cost of sales increased by $10.8 billion and $10.4 billion, respectively, which equates to an increase in gross margin of $432.9 million. This significant increase in revenues and cost of sales is primarily a result of the adoption of EITF 02-3, as discussed previously.

Power's gross margin increased $432.9 million principally due to $579.4 million higher power and natural gas gross margin partially offset by $108.8 million lower emerging products gross margin and $38.2 million lower petroleum products gross margin.

The power and natural gas gross margin increased $579.4 million from a margin loss of $332.4 million in 2002 to a $247 million gross margin in 2003. The $247 million gross margin in 2003 is primarily comprised of a $171.7 million accrual loss offset by a $338.1 million mark-to-market gain and $80.7 million in revenues in the second quarter 2003 attributable to prior periods. In the second-quarter of 2003, Power began accounting for certain of its power and gas derivatives contracts under the accrual method of accounting as a result of an election to account for the contracts under the normal purchases and sales exception available under SFAS No. 133. These contracts were previously marked to market with changes in fair value reported within earnings. The prior period corrections relate to the fair value of these derivative contracts and do not represent actual current period cash flows. Refer to Note 1 of Notes to the Consolidated Financial Statements for further information. The accrual loss of $171.7 million is primarily related to narrower spark spreads. Of the $338.1 million mark-to-market gain, $126.8 million is a positive valuation adjustment to a derivative contract based on the terms of an agreement to terminate the contract. The other mark-to-market gains are primarily a result of increased gas prices in 2003 on long natural gas positions. In 2002, all energy-related trading contracts, including tolling and full requirements contracts, were marked to market. In 2003, with the implementation of EITF 02-3 as discussed previously, these non-derivative energy-related trading contracts were accounted for on an accrual basis. Therefore, 2002 earnings reflected the unfavorable impact of narrower spark spreads in future periods on certain power tolling portfolios and a valuation adjustment of $74.8 million as a result of market information obtained through sales efforts on certain full requirements contracts. In contrast, in 2003, the earnings for these types of contracts are reported on an accrual basis. Therefore, any forward gains or losses resulting from changes in fair value are excluded from current earnings for non-derivative contracts, whereas the changes in forward value of certain derivatives contracts continue to be included in earnings. The 2003 mark-to-market gains are partially offset by an $85.1 million decrease in power and gas revenues from the origination of significant new long-term transactions in 2002 and a $37 million adjustment in first-quarter 2003 to increase the liability for rate refunds associated with 2003 FERC rulings relative to California power and natural gas markets.

The petroleum products portfolio gross margin decreased from $4.3 million in 2002 to a margin loss of $33.9 million in 2003. The $33.9 million gross margin loss in 2003 is primarily comprised of a $23.7 million accrual loss and a $10.2 million mark-to-market loss. The decrease in gross margin of $38.2 million was primarily attributable to a $118.8 million decrease in revenues from the origination of significant new long-term transactions in 2002 partially offset by the impact of the implementation of EITF 02-3 in 2003. The petroleum products portfolio was adversely affected in 2002 by a decrease in the forward value of refined products storage and transportation portfolios. Pursuant to EITF 02-3, these same non-derivative storage and transportation contracts were required to be treated on an accrual basis in 2003, resulting in a comparatively higher gross margin attributable to these contracts.

The emerging products portfolio gross margin decreased from $85.2 million in 2002 to a mark-to-market margin loss of $23.6 million in 2003. The $108.8 million decrease in emerging products gross margin is primarily attributable to falling interest rates on forward interest rate positions that are marked to market.

Selling, general, and administrative expenses decreased by $72.9 million, or 41 percent. This cost reduction is due primarily to the impact of employee reductions in the Power business segment.

Other (income) expense - net increased $348 million. This increase is primarily due to a $188 million gain from the sale of an energy trading contract in 2003, a $13.5 million gain from the sale of Power's investment in eSpeed common stock and the effect in 2002 of $95.2 million of impairments and loss accruals associated with certain terminated power projects and a $57.5 million partial goodwill impairment. The 2003 increase was partially offset by a $20 million charge for the settlement reached with the Commodity Futures Trading Commission (see Note 11).

Segment profit increased $857.5 million due primarily to increased power and natural gas gross margins, decreased selling, general and administrative expenses and improved other (income) expense- net, partially offset by decreased petroleum products and emerging products gross margins as discussed above.

GAS PIPELINE

	THREE MONTHS ENDED SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2003	2002	2003	2002
	(MILLIONS)			
Segment revenues	$ 316.6	$ 324.0	$ 951.9	$ 919.5
Segment profit	$ 141.4	$ 147.2	$ 406.5	$ 423.0

On April 14, 2003, Williams announced that it had signed a definitive agreement to sell Texas Gas Transmission Corporation (Texas Gas) to Loews Pipeline Holding Corp., a unit of Loews Corporation. The sale closed on May 16, 2003. Williams received $799 million in cash and the buyer assumed $250 million in debt. Pursuant to current accounting guidance, the operations of Texas Gas have been classified as discontinued operations.

For the purposes of third-quarter 2003 reporting, Gas Pipeline's continuing operations include Northwest Pipeline Corporation (Northwest Pipeline), Transcontinental Gas Pipe Line Corporation (Transco), a 50 percent interest in Gulfstream and other joint venture interstate and intrastate natural gas pipeline systems. Certain assets sold during 2002 are included in the 2002 results. These assets include Cove Point, a general partner interest in Northern Border, and our 14.6 percent interest in Alliance Pipeline. These assets represented $1.7 million and $7.4 million of revenues for the three months and nine months ended September 30, 2002, respectively, and $1.4 million and $14.0 million of segment profit for the three and nine months ended September 30, 2002, respectively. Financial results related to Kern River, Central, (both sold during 2002), and Texas Gas are included in discontinued operations.

Three Months Ended September 30, 2003 vs. Three Months Ended September 30, 2002

GAS PIPELINE'S revenues decreased $7.4 million, or two percent, due primarily to $26 million in reductions in the rate refund liabilities and other adjustments associated with a rate case settlement on Transco in 2002 and $4 million lower storage demand revenues due to lower storage rates in connection with Transco's rate proceedings that became effective in late 2002. Partially offsetting these decreases were $16 million higher demand revenues on the Transco system resulting from new expansion projects (MarketLink, Momentum and Sundance) and higher transportation rates in connection with rate proceedings that became effective in late 2002, $6 million of additional revenue on the Northwest Pipeline system primarily from new projects (Gray's Harbor, Centralia, and Chehalis) and $6 million higher cash-out sales related to gas imbalance settlements (offset in costs and operating expenses).

Cost and operating expenses increased $16 million, or 11 percent, due primarily to $6 million higher depreciation expense and $4 million higher ad valorem taxes resulting from increased property, plant and equipment placed into service and $6 million higher cash-out sales related to gas imbalance settlements (offset in revenues).

General and administrative costs decreased $10 million, or 22 percent, due primarily to lower salaries, benefits, and other related costs resulting from employee reductions.

Other (income) expense - net in 2003 includes $7.2 million of income at Transco resulting from a partial reduction of accrued liabilities for claims associated with certain producers as a result of recent settlements and court rulings (see Note 11).

Segment profit, which includes equity earnings and income (loss) from investments (included in investing income), decreased $5.8 million reflecting $7.4 million lower revenues, $16 million higher costs, $10 million lower general and administrative expenses, and other income discussed above. The decrease also reflects the absence of an $8.7 million gain on sale of the general partnership interest in Northern Border Partners, L.P., in 2002. Partially offsetting the decreases above is the net effect of the absence of a $11.6 million net impairment charge on Gas Pipeline's 14.6 percent ownership in Alliance Pipeline, which was sold in October 2002, and $6 million of related equity earnings.

Nine Months Ended September 30, 2003 vs. Nine Months Ended September 30, 2002

GAS PIPELINE'S revenues increased $32.4 million, or four percent, due primarily to $48 million higher demand revenues on the Transco system resulting from new expansion projects (MarketLink, Momentum and Sundance) and higher rates authorized under Transco's rate proceedings that became effective in late 2002, $15 million on the Northwest Pipeline system resulting from new projects (Gray's Harbor, Centralia, and Chehalis) and $5 million higher transportation revenues on the Northwest Pipeline system. Partially offsetting these increases were $26 million in reductions in the rate refund liabilities and other adjustments associated with a rate case settlement on Transco in 2002, $12 million lower storage demand revenues due to lower storage rates in connection with Transco's rate proceedings that became effective in late 2002, and $5 million lower cash-out sales related to gas imbalance settlements (offset in costs and operating expenses).

Cost and operating expenses increased $3 million, or one percent, due primarily to $14 million higher depreciation expense due to increased property, plant and equipment placed into service and $6 million higher tracked costs which are passed through to customers (offset in revenues). These increases were partially offset by $15 million lower fuel expense on Transco, resulting primarily from pricing differentials on the volumes of gas used in operation, and $5 million lower cash-out sales related to gas imbalance settlements (offset in revenues).

General and administrative costs decreased $29 million, or 24 percent, due primarily to the absence of $16 million of 2002 early retirement pension costs and reductions to employee-related benefits accruals.

Other (income) expense - net in 2003 includes a $25.5 million charge at Northwest Pipeline to write-off capitalized software development costs for a service delivery system. Subsequent to the implementation of the same system at Transco in the second quarter of 2003 and a determination of the unique and additional programming requirements that would be needed to complete the system at Northwest Pipeline, management determined that the system would not be implemented at Northwest Pipeline. Other (income) expense - net in 2003 also includes $7.2 million of income at Transco due to a partial reduction of accrued liabilities for claims associated with certain producers as a result of recent settlements and court rulings.

Segment profit, which includes equity earnings and income (loss) from investments (included in investing income), decreased $16.5 million, or 4 percent, due to $73 million lower equity earnings, the $25.5 million charge at Northwest Pipeline discussed previously, and $3 million higher operating costs. These decreases to segment profit were partially offset by $32.4 million higher revenues, $29 million lower general and administrative costs discussed above, and the absence of a $12.3 million 2002 write-off of Gas Pipeline's investment in a cancelled pipeline project (income (loss) from investment). The $73 million decrease to equity earnings reflects $27 million lower equity earnings from Gulfstream, the absence of a $27.4 million benefit in 2002 related to the contractual construction completion fee received by an equity affiliate and the absence of $17 million of equity earnings following the October 2002 sale of Gas Pipeline's 14.6 percent ownership in Alliance Pipeline. The lower earnings for Gulfstream were primarily due to the absence in 2003 of interest capitalized on internally generated funds as allowed by the FERC during construction. The pipeline was placed into service during second-quarter 2002.

EXPLORATION & PRODUCTION

THREE
MONTHS NINE
MONTHS
ENDED
SEPTEMBER
30, ENDED
SEPTEMBER
30, -------

2003 2002
2003 2002 -

(MILLIONS)

Segment revenues	$ 168.7	$ 209.4	$ 612.8	$ 652.2
Segment profit	$ 58.8	$ 228.2	$ 351.3	$ 427.1

On February 20, 2003, Williams announced that it was evaluating the sale of additional assets including selected Exploration & Production properties. During second-quarter 2003, Williams completed a substantial portion of the targeted asset sales from the Exploration & Production segment that included sales of properties located primarily in Kansas, Colorado and New Mexico. During the third quarter of 2003, Williams sold additional properties in Utah and Colorado, thus completing the targeted sales. The completed sales represented approximately 16 percent of Williams' proved domestic reserves at December 31, 2002. Exploration & Production has received net proceeds of approximately $464 million resulting in net pre-tax gains of approximately $134.9 million, including $39.7 million of pre-tax gains reported in discontinued operations related to the interests in the Raton and Hugoton basins. The following discussion relates to the continuing operations of Exploration & Production and those operations that were sold but do not qualify for discontinued operations reporting.

Three Months Ended September 30, 2003 vs. Three Months Ended September 30, 2002

EXPLORATION & PRODUCTION'S revenues decreased $40.7 million, or 19 percent, due primarily to $28 million lower domestic production revenues resulting largely from a 13 percent decrease in net domestic production volumes in addition to lower realized sales prices (including the impact of hedge positions). The decrease in production volumes primarily results from the impact of reduced drilling activity in January through August of this year due to capital constraints and the absence of volumes from properties sold in 2002 and 2003. During the third quarter, the drilling activities on our retained properties returned to levels more consistent with 2002 drilling activities. The drilling activities are expected to increase production volumes in the future. Approximately 90 percent of all domestic production during third-quarter 2003 was hedged. Exploration & Production has contracts that hedge approximately 82 percent of estimated production for the remainder of 2003 at prices that average $3.78 per million cubic feet equivalent (mcfe) at the basin level. In addition, Exploration & Production has contracts that hedge approximately 80 percent of estimated production in 2004 at prices that average $3.63 per mcfe at the basin level. Exploration & Production also has contracts that hedge approximately 50 percent of estimated 2005 production at prices that average above $4.00 per mcfe at the basin level. Most all of the derivative contracts are entered into with Power which in turn enters into offsetting derivative contracts with unrelated third parties. Generally, Power bears the counterparty performance risks associated with unrelated third parties. Exploration & Production also has derivative contracts with Power that no longer qualify for hedge accounting treatment (as a result of asset sales) or were never designated in hedge relationships. The changes in fair value of these contracts are recognized in revenues. The total impact, realized and unrealized, of these instruments on 2003 revenues was a $1 million gain as compared to a $7 million gain in 2002.

Costs and expenses, including selling, general and administrative expenses, decreased $6 million, including $4 million decrease in selling, general and administrative expense, $3 million lower depreciation, depletion and amortization expense and $3 million lower lease operating expense. The decrease in selling general and administrative costs reflects reduced consulting fees and lower compensation expense. The decreased depreciation, depletion and amortization expense is due to the previously discussed asset sales and lower production volumes. These decreases were partially offset by $5 million higher operating taxes due primarily to higher market prices in 2003.

Other (income) expense - net in 2002 includes approximately $143.9 million in gains from the sales of certain interests in natural gas properties during third-quarter 2002.

Segment profit decreased $169.4 million due primarily to the gains on the sales of assets in 2002 that were discussed above and the lower production revenues.

Nine Months Ended September 30, 2003 vs. Nine Months Ended September 30, 2002

EXPLORATION & PRODUCTION'S revenues decreased $39.4 million, or six percent due primarily to $42 million lower production revenues. The lower domestic production revenues reflect $51 million lower revenues due to a ten percent decrease in net domestic production volumes, partially offset by $9 million higher revenues from increased net realized average prices for production (including the effect of hedge positions). The decrease in production volumes primarily results from the sales of properties in 2002 and 2003, partially offset by increased production volumes for properties retained. Approximately 87 percent of all domestic production during the first nine months of 2003 was hedged.

Costs and expenses, including selling, general and administrative expenses, decreased $2 million including $8 million lower exploration expenses, $3 million lower depreciation, depletion and amortization expense, and $3 million lower selling general and administrative expense offset by $16 million higher operating taxes due primarily to higher market prices. The lower exploration expenses reflect the current focus of the company on developing proved properties while reducing exploratory activities.

Other (income) expense - net in 2003 includes approximately $95.3 million in net gains on sales of assets during 2003, which were discussed previously. Other (income) expense - net in 2002 includes approximately $147 million in net gains on sales of natural gas properties during 2002.

Segment profit decreased $75.8 million due primarily to $52 million lower net gains in 2003 on sales of assets as compared to 2002, which are discussed above. Additionally, lower production revenues due primarily to lower production volumes also contributed to the decrease.

MIDSTREAM GAS & LIQUIDS

	THREE MONTHS ENDED SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2003	2002	2003	2002
(MILLIONS)				
Segment revenues	$ 841.0	$ 405.5	$ 2,485.6	$ 1,096.4
Segment profit				
Domestic Gathering & Processing	$ 57.4	$ 73.3	$ 217.7	$ 131.1
Venezuela	23.5	17.8	57.0	55.9
Canada	(6.4)	7.9	(17.7)	7.4
Other	(0.2)	12.6	(16.9)	15.8
Total Segment Profit	$ 74.3	$ 111.6	$ 240.1	$ 210.2

Midstream has announced its intention to sell certain assets, including certain operations in Canada. During the third quarter of 2003, Midstream completed the sales of its West Stoddart gas processing facility and the fractionation, storage, and distribution system at its Redwater, Alberta plant in western Canada. Midstream also completed the sale of its 45 percent interest in the Rio Grande pipeline in second-quarter and its 20 percent interest in the West Texas Pipeline Limited Partnership in third-quarter 2003. In October, Midstream closed the sale of its 37.5 percent interest in Wilprise Pipeline Co. and its 16.67 percent interest in Tri-states NGL Pipeline LLC. Midstream continues to evaluate and pursue various asset sale transactions, including the assets of its wholly owned subsidiary Gulf Liquids New River LLC (Gulf Liquids). In June 2003, Williams' Board of Directors authorized management to sell Gulf Liquids.

Midstream expects that the completion of asset sales will have the effect of lowering revenues and/or segment profit in the periods following the sales. However, continued growth in the deepwater areas of the Gulf of Mexico are expected to contribute to future segment revenues and segment profit mitigating the decline from asset sales.

Pursuant to current accounting guidance, Midstream has classified the operations of Gulf Liquids, certain natural gas processing operations in western Canada and Redwater extraction as discontinued operations. All prior periods reflect this reclassification.

Three Months Ended September 30, 2003 vs. Three Months Ended September 30, 2002

Midstream revenues increased $436 million due primarily to the effect of a change in the reporting of NGL trading activities for which costs are no longer netted in revenues as a result of the application of EITF 02-3. In addition to this effect, Midstream's revenues increased $61 million due primarily to higher NGL revenues resulting from higher market prices partially offset by lower volumes at the Canadian gas processing plants. While domestic NGL revenues were lower as a result of less favorable processing economics, additional fee-based revenues generated by new deepwater assets offset this decline. Additionally, Olefins revenues increased due to higher sales volumes and prices at both domestic and Canadian facilities.

Cost and operating expenses increased $478 million due primarily to the adoption of EITF 02-3 as discussed above. In addition to this effect, costs and expenses increased $103 million, of which, $94 million is attributable to higher market prices for natural gas used to replace the heating value of NGL's extracted at Midstream's gas processing facilities. The remaining increase is due primarily to higher market costs for NGL's used as feedstock to produce olefins, increased maintenance spending, and higher depreciation, partially offset by lower selling, general and administrative expenses.

Segment profit declined by $37.3 million primarily as a result of reduced gas processing margins reflecting a lower processing spread between the price earned for producing NGL's compared to the price of natural gas used to replace the heating value of the NGL's. In particular, the price of natural gas in third-quarter 2003 increased significantly compared to third-quarter 2002. While higher long-term natural gas prices tend to increase demand for Midstream's gathering and processing services, the short-term price increase compared to third-quarter 2002 adversely impacted gas processing margins. Lower net trading margins and a decline in equity earnings have also contributed to the segment profit reduction. However, gains on sales of investments, additional fee revenues from new infrastructure in the deepwater fields in the Gulf of Mexico, and the benefit of more favorable contractual arrangements concerning existing Gulf Coast processing facilities partially offset the decline. A more detailed analysis of segment profit of Midstream's operations is presented below:

Domestic Gathering & Processing: Midstream's domestic gathering and processing segment profit declined $15.9 million, with the West Region recording a $31.2 million decline, partially offset by a $15.3 million increase in the Gulf Coast Region. The decline in the West Region is attributable to a $24.5 million decline in gas processing margins due to natural gas prices that increased to a greater degree than NGL prices during this period. In third-quarter 2002, the West Region experienced very favorable processing margins due to depressed natural gas prices created by transportation constraints for gas production in the Wyoming area. Consequently, natural gas prices in Wyoming were approximately 38 percent lower than those in the Gulf Coast markets during the third quarter of 2002. The completion of the Kern River Pipeline system expansion in 2003 relieved the transportation constraints in Wyoming. As a result, the favorable Wyoming gas price differential fell from $2 per MMBtu in third-quarter 2002 to $.48 per MMBtu in third-quarter 2003. In the Gulf Coast Region, segment profit increased $15.9 million attributable to $10.6 million in incremental net profits associated with recently completed infrastructure located in the deepwater area in the Gulf of Mexico. This region also benefited from higher revenues derived from temporary gas treating agreements which provided incentives to Gulf Coast processors to remove hydrocarbon liquids from producers' gas as required to meet quality standards of interstate gas pipelines. Most gas processing in the Gulf Coast had been shut down due to uneconomic processing conditions. As a result, pipelines began enforcing their gas quality tariffs and required gas producers to have a contract with a processing plant before they would allow the gas to enter the interstate pipeline grid. Midstream would expect these temporary arrangements to remain in place as long as the processing environment remains unfavorable.

Venezuela: Segment profit increased $5.7 million, primarily attributable to higher processing revenue at the PIGAP facility due to processing fees being calculated using a variety of indices, including the Venezuelan rate of inflation, which was somewhat higher during the quarter. The Venezuelan economic and political environment remains fluid and volatile, but has not significantly impacted the operations and cash flows of Midstream's facilities. Midstream's Venezuelan operations were constructed and are currently operated for the exclusive benefit of Petroleos de Venezuela (PDVSA), the state-owned petroleum company of Venezuela. Contracts with PDVSA stipulate a majority of the payment to be in U.S. dollars and provide protection against the devaluation and lack of liquidity of the Venezuelan Bolivar. These contracts also provide for adjustments for inflation and minimum volume guarantees provided plants are operational.

Canada: Midstream's Canadian segment profit declined $14.3 million due primarily to lower gas processing margins and lower olefins margins. Gas processing margins from extraction facilities fell $8.6 million due to gas purchase prices increasing at a greater rate than NGL sales prices. Olefins sales margins declined $5 million primarily due to a $2.8 million inventory adjustment and higher feedstock costs.

Other: Segment profit for Midstream's other operations declined $12.8 million due to lower trading revenues, lower domestic olefins margins and lower earnings from investments.

Segment profit for Midstream's domestic olefins activities declined $7.1 million as a result of reduced olefins margins as the price of feedstock (ethane and propane) increased more than the price of olefins products. The decline in Olefins margins continues to reflect the decline in olefins product prices that are largely driven by the consumer product markets softening against the rising energy commodity markets.

Segment profit for NGL trading, fractionation, and storage operations declined by $4.4 million, primarily as a result of a $9.4 million decline in NGL trading earnings, partially offset by $3.4 million in lower selling, general and administrative costs reflecting the decline in liquids trading operations. Third-quarter 2003 trading results reflect an overall margin of $1.5 million, compared to a margin of $10.9 million realized in the same period of 2002 resulting from long NGL positions in a rising market. Lower operations and maintenance spending on the NGL fractionation and storage facilities also reduce segment profit.

Midstream's earnings from partially-owned investments accounted for on the equity method declined $1.3 million due largely to $4 million in lower earnings at Discovery Pipeline (Discovery) and the absence of earnings from the Rio Grande and West Texas Pipeline investments, which were sold in 2003. Partially offsetting the decline in segment profit is the current period net difference between an $11 million net gain on the sale of Midstream's interest in the West Texas Pipeline partnership and a $5.6 million impairment of the partnership investment in Aux Sable Liquid Products, L.P. (Aux Sable). The impairment resulted from management's assessment that there had been an other than temporary decline in the fair value of this investment.

Nine Months Ended September 30, 2003 vs. Nine Months Ended September 30, 2002

Midstream revenues increased $1.4 billion due primarily to the effect of a change in the reporting of natural gas liquids trading activities for which costs are no longer netted in revenues as a result of the application of EITF 02-3. In addition to this effect, Midstream's revenues increased $327 million primarily resulting from increased NGL sales at gas processing plants caused by higher NGL prices partially offset by lower volumes in both domestic and Canadian markets. Although Gulf Coast NGL revenues were lower as a result of less favorable processing economics, additional fee-based revenues generated by new deepwater assets more than offset this decline. Additionally, olefins sales increased due to increased sales and higher prices at both domestic and Canadian facilities.

Cost and operating expenses also increased $1.3 billion due primarily to the adoption of EITF 02-3 as discussed above. In addition to this effect, costs and expenses increased $285 million, of which $227 million is attributable to modestly higher market prices for natural gas used to replace the heating value of NGL's extracted at Midstream's gas processing facilities. Feedstock purchases for the olefins facilities increased $81.4 million due to both higher NGL prices and sales volumes. In addition, lower selling, general and administrative expenses, and lower other operating costs were partially offset by higher depreciation expense resulting from the new deepwater operations.

Segment profit increased $30 million due primarily to the additional net profit contribution of the deepwater assets, the majority of which were placed in service during the fourth quarter of 2002. Despite monthly fluctuations, average gas processing margins for the nine months of 2003 were somewhat comparable with the first nine months of 2002. These margins increased steadily each quarter in 2002 as NGL prices rose at a greater rate than natural gas prices. After peaking in the first quarter of 2003, processing margins deteriorated in the second quarter as NGL prices fell while gas prices continued to increase, particularly in the Wyoming area. In addition, lower partnership earnings and asset impairment charges were offset by reduced selling, general and administrative expenses and a net gain on the sale of an investment. A more detailed analysis of segment profit of Midstream's various operations is presented below:

Domestic Gathering & Processing: Midstream's domestic gathering and processing segment profit improved $86.6 million with the Gulf and West Regions recording $70 million and $16.2 million increases, respectively.

The Gulf Region's $70.4 million increase is largely attributable to $38.4 million of incremental operating profit associated with new infrastructure in the deepwater area of the Gulf of Mexico. The Canyon Station production platform, Seahawk gas gathering pipeline, and Banjo oil transportation system were placed into service during the latter half of 2002 and each contributed to Midstream's segment profit. The Gulf Coast gas processing plants provided approximately $25 million in additional revenues from $7 million in higher processing margins and $19 million in higher fee-based revenues. A portion of this increase relates to the temporary processing agreements created to allow producers' gas to be processed to achieve pipeline quality standards. Also, higher gathering volumes originating from new deepwater production, combined with lower operating expenses, resulted in $12 million of additional segment profit recorded on the regulated gas gathering system.

The West Region's $16.2 million increase in segment profit includes a $7 million decline resulting from the August 2002 sale of the Kansas Hugoton gathering system. Bolstered by depressed natural gas prices in Wyoming, processing margins in the West Region grew steadily throughout 2002 as NGL prices increased. After peaking in the first quarter of 2003, processing margins fell considerably in the following two quarters as natural gas prices climbed in response to additional gas pipeline capacity relieving the downward price pressure. Gas processing margins for the first nine months of 2003 were slightly less than those of the same period in 2002. Segment profits were higher largely due to more efficient operations with favorable variances realized from lower maintenance expense and lower fuel purchases.

Venezuela: Segment profit increased $1.1 million, primarily as a result of a $13 million increase in operating profit at the PIGAP gas compression facility offset largely by a $10 million decrease in the El Furrial operating margins due primarily to plant downtime resulting from a fire at the plant during the first quarter of 2003. Also offsetting the increase in PIGAP operating profit is a $2 million decline resulting from the termination by PDVSA of the Jose Terminal operations contract in December 2002. The year-to-date decline in operating profit resulting from the termination of this contract is indicative of the decline expected to occur over future periods. However, the outcome of arbitration with PDVSA regarding the termination of this contract could impact the operating profit of Midstream's Venezuelan operations in future periods.

Canada: Midstream's Canadian segment profit declined $25.1 million, due primarily to $6 million in lower gas processing margins caused by gas prices increasing at a greater rate than NGL prices. Operating expenses were $11 million higher, most of which are attributed to the olefins facility that became operational in April 2002. In addition, currency transaction losses were higher due to the decline of the U.S. dollar.

Other: Segment profit for Midstream's other operations fell $32.7 million due to lower trading revenues, lower domestic olefins margins, and lower earnings from investments.

Segment profit for Midstream's domestic olefins activities declined $14.9 million as a result of reduced olefins fractionation margins as the price of feedstock (ethane and propane) increased more than the price of olefins products. Higher maintenance expenses also contributed to the decline in segment profit.

Segment profit for Midstream's NGL trading, fractionation, and storage operations increased $1 million, primarily as a result of $12 million in lower selling, general and administrative costs related to NGL trading activities. This increase is offset by an $8 million decline in liquids trading operations and lower NGL handling fees caused by the sale of several NGL terminals in 2002.

Midstream's earnings from partially-owned investments accounted for on the equity method declined $18.8 million due largely to a $13.4 million charge against Midstream's investment in Discovery reflecting adjustments to expense certain amounts capitalized in periods prior to Williams becoming the operator, and the sale of other investments which generated positive earnings in 2002. Also included in 2003 segment profit were net gains totaling approximately $15.8 million on the sale of Midstream's interests in the West Texas and Rio Grande liquids pipeline partnerships and $14.1 million of impairment charges associated with the Aux Sable partnership investment.

OTHER

	THREE MONTHS ENDED SEPTEMBER 30,		NINE MONTHS ENDED SEPTEMBER 30,	
	2003	2002	2003	2002
(MILLIONS)				
Segment revenues	$ 11.0	$ 26.0	$ 59.1	$ 78.7
Segment profit (loss)	$ 4.1	$ 47.4	$ (42.8)	$ 34.9

Other segment loss for the nine months ended September 30, 2003 includes a $42.4 million impairment related to the investment in Longhorn. Other segment profit for the three and nine months ended September 30, 2002 includes a $58.5 million gain on the sale of Williams' 27 percent ownership interest in the Lithuanian operations. The impairment resulted from management's assessment that there had been an other than temporary decline in the fair value of this investment.

FAIR VALUE OF ENERGY RISK MANAGEMENT AND TRADING ACTIVITIES

The chart below reflects the fair value of energy trading derivatives for Power and Midstream that have been assessed to be trading contracts, separated by the year in which the recorded fair value is expected to be realized. As of December 31, 2002, Power reported a net asset of approximately $1,632 million related to the fair value of energy risk management and trading contracts. With the adoption of EITF 02-3 on January 1, 2003, approximately $1,193 million of that pre-tax fair value pertained to non-derivative energy contracts, and this amount was reversed through a cumulative adjustment from a change in accounting principle. Trading contracts are accounted for using the mark to market accounting method. The table of trading contracts presented below includes the fair value as of September 30, 2003 of only those contracts that are held to provide price risk management services to third party customers or that do not hedge or that could not reasonably be considered an economic hedge to mitigate Power's or Midstream's own long-term structured contract positions. Also, the table below does not reflect the fair value of non-derivative energy contracts which was reversed in the cumulative accounting change adjustment recorded in the first quarter of 2003.

(MILLIONS)

TO BE REALIZED IN 1-12 MONTHS (YEAR 1)	TO BE REALIZED IN MONTHS 13-36 (YEARS 2-3)	TO BE REALIZED IN MONTHS 37-60 (YEARS 4-5)	TO BE REALIZED IN MONTHS 61-120 (YEARS 6-10)	TO BE REALIZED IN MONTHS 121+ (YEARS 11+)	TOTAL FAIR VALUE OF TRADING DERIVATIVES
$56	$(44)	$(19)	$4	$2	$(1)

Power holds a substantial portfolio of non-trading derivative contracts. Certain of these have not been designated as or do not qualify as SFAS No. 133 hedges, and are accounted for using the mark to market method of accounting. As of September 30, 2003 the fair value of these non-trading derivative contracts was a net asset of $728 million. Power also holds a number of SFAS No. 133 cash flow hedges on behalf of other business units, hedges associated with owned generation assets, and other miscellaneous hedges. As of September 30, 2003 the fair value of these hedges was a net liability of approximately $156 million. Various other business units within Williams also possess certain SFAS No. 133 hedge liabilities of approximately $25 million.

ESTIMATES AND ASSUMPTIONS REGARDING COUNTERPARTY PERFORMANCE AND CREDIT RISK CONSIDERATIONS

Power and Midstream include in their estimate of fair value for all derivative contracts an assessment of the risk of counterparty non-performance. Such assessment considers the credit rating of each counterparty as represented by public rating agencies such as Standard & Poor's and Moody's Investors Service, the inherent default probabilities within these ratings, the regulatory environment that the contract is subject to, as well as the terms of each individual contract.

Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of the cash flows expected to be realized. Power and Midstream continually assess this risk and have credit protection within various agreements to call on additional collateral support in the event of changes in the creditworthiness of the counterparty. Additional collateral support could include letters of credit, payment under margin agreements, guarantees of payment by creditworthy parties, or in some instances, transfers of the ownership interest in natural gas reserves or power generation assets. In addition, Power and Midstream enter into netting agreements to mitigate counterparty performance and credit risk.

The gross forward credit exposure from Power's and Midstream's derivative contracts as of September 30, 2003 is summarized as below.

COUNTERPARTY TYPE	INVESTMENT GRADE (a)	TOTAL
	(MILLIONS)	
Gas and electric utilities	$ 1,168.9	$ 1,262.8
Energy marketers and traders	2,145.7	4,129.8
Financial Institutions	969.4	969.4
Other	729.6	758.3
	$ 5,013.6	$ 7,120.3
Credit reserves		(50.2)
Gross Credit Exposure from Derivative Contracts (b)		$ 7,070.1

In addition to the gross Power and Midstream derivative exposure discussed above, other business units within Williams possess an additional $29 million in gross derivative asset exposure.

Power and Midstream assess their credit exposure on a net basis when appropriate and contractually allowed. The net forward credit exposure from Power's and Midstream derivative contracts as of September 30, 2003 is summarized as below.

COUNTERPARTY TYPE	INVESTMENT GRADE (a)	TOTAL
	(MILLIONS)	
Gas and electric utilities	$ 650.9	$ 660.5
Energy marketers and traders	55.1	63.1
Financial Institutions	53.0	53.0
Other	4.0	7.8
	$ 763.0	784.4
Credit reserves		(50.2)
Net Credit Exposure from Derivative Contracts (b)		$ 734.2

- ----------

(a) "Investment Grade" is primarily determined using publicly available credit ratings along with consideration of cash, standby letters of credit, parent company guarantees, and property interests, including oil and gas reserves. Included in "Investment Grade" are counterparties with a minimum Standard & Poor's and Moody's Investor's Service rating of BBB- or Baa3, respectively.

(b) One counterparty within the California power market represents greater than ten percent of derivative assets and is included in "investment grade." Standard & Poor's and Moody's Investors Service do not currently rate this counterparty. This counterparty has been included in the "investment grade" column based upon contractual credit requirements in the event of assignment or novation.

The overall net credit exposure from derivative contracts of $734.2 million at September 30, 2003, represents an overall decrease in derivative credit exposure of approximately 40 percent on a comparable basis from December 31, 2002. In 2002 and 2003, Power closed out various trading positions and as a result has not suffered significant losses due to recent bankruptcy filings. Credit constraints, declines in market liquidity, and financial instability of market participants, are expected to continue and potentially worsen in 2003. Continued liquidity and credit constraints of Williams may also significantly impact Power's ability to manage market risk and meet contractual obligations.

Electricity and natural gas markets, in California and elsewhere, continue to be subject to numerous and wide-ranging federal and state regulatory proceedings and investigations, as well as civil actions, regarding among other things, market structure, behavior of market participants, market prices, and reporting to trade publications. Power may be liable for refunds and other damages and penalties as a part of these actions. Each of these matters as well as other regulatory and legal matters related to Power are discussed in more detail in Note 11 of Notes to the Consolidated Financial Statements. The outcome of these matters could affect the creditworthiness and ability to perform contractual obligations of Power as well as the creditworthiness and ability to perform contractual obligations of other market participants.

FINANCIAL CONDITION AND LIQUIDITY

LIQUIDITY

Williams' liquidity is derived from both internal and external sources. Certain of those sources are available to Williams (the parent) and others are available to certain of its subsidiaries. Williams' sources of liquidity consist of the following:

- Cash-equivalent investments at the corporate level of $2.9 billion at September 30, 2003, as compared to $1.3 billion at December 31, 2002

- Cash and cash-equivalent investments of various international and domestic entities of $532 million at September 30, 2003 as compared to $352 million at December 31, 2002

- Cash generated from sales of assets

- Cash generated from operations

- $378 million available under Williams' current revolving credit facility at September 30, 2003. This new facility is primarily for the purpose of issuing letters of credit and must be collateralized at 105 percent of the level utilized (see Note 10). At December 31, 2002, Williams had a combined $480 million available under the previous revolving and letter of credit facilities.

Williams has an effective shelf registration statement with the Securities and Exchange Commission that enables it to issue up to $3 billion of a variety of debt and equity securities. Subsequent to the $800 million issuance of senior unsecured securities on June 10, 2003, the current availability under this shelf registration is $2.2 billion.

In addition, there are outstanding registration statements filed with the Securities and Exchange Commission for Williams' wholly owned subsidiaries: Northwest Pipeline and Transco. As of November 5, 2003, approximately $350 million of shelf availability remains under these outstanding registration statements and may be used to issue a variety of debt securities. Interest rates, market conditions, and industry conditions will affect amounts raised, if any, in the capital markets. On March 4, 2003, Northwest Pipeline completed an offering of $175 million of 8.125 percent senior notes due 2010. The $350 million of shelf availability mentioned above was not affected by this offering.

Capital and investment expenditures for 2003 are estimated to total approximately $1 billion. Williams expects to fund capital and investment expenditures, debt payments and working-capital requirements through (1) cash on hand, (2) cash generated from operations, (3) the sale of assets, and/or (4) amounts available under Williams' revolving credit facility.

Outlook

Williams expects to generate proceeds, net of related debt, of approximately $4 billion during 2003 and 2004. Through September 30, 2003, Williams has received $2.8 billion in net proceeds from the sale of assets and $315 million from the sale and/or termination of certain marketing and trading contracts.

Also, the Company's board of directors has approved resolutions that authorize management to negotiate and facilitate the sales of the assets of Gulf Liquids New River Project LLC and Williams' Alaska operations. In October 2003, Williams completed the sale of its interest in two natural gas liquids pipelines for $26.5 million. These assets were previously identified for divestiture.

Included in the $315 million is $100 million received in September 2003 associated with the expected termination of Williams long-term power contract with Allegheny Energy Supply Company, LLC, a subsidiary of Allegheny Energy, Inc. Williams anticipates it will terminate the supply contract upon its receipt of the final $28 million of the termination payment, which is due in installments of $14 million to be paid in the first and third quarters of 2004.

Based on its forecast of cash flows and liquidity, Williams believes that it has, or has access to, the financial resources and liquidity to meet future cash requirements. For the remainder of 2003 and through first-quarter 2004, the Company has scheduled debt retirements of approximately $1.6 billion. In the third quarter of 2003, Williams' Board of Directors authorized the Company to retire or otherwise prepay up to $1.8 billion of debt, including $1.4 billion designated for the Company's 9.25% notes due March 15, 2004. On October 8, 2003, the Company announced a cash tender offer for any and all of Williams' $1.4 billion senior unsecured 9.25 percent notes due in March 2004, as well as cash tender offers and consent solicitations for approximately $241 million of additional notes and debentures. As of October 31, 2003, approximately $720 million of the 9.25 percent notes had been accepted for purchase. Additionally, Williams received tenders of notes and deliveries of related consents from holders of approximately $230 million of the other notes and debentures. The tender offers are scheduled to expire on November 6, 2003.

OPERATING ACTIVITIES

For the nine months ended September 30, 2003, Williams recorded approximately $133.5 million in provisions for losses on property and other assets consisting primarily of a $42.4 million impairment of Williams' investment in Longhorn, a $25.5 million charge related to the write-off of software development costs at Northwest Pipeline, a $14.1 million impairment of Williams investment in Aux Sable, a $13.5 million impairment of an investment in a company holding phosphate reserves and a $13.2 million impairment of Algar.

The net gain on disposition of assets primarily consists of the gains on the sales of natural gas properties during second-quarter 2003.

The accrual for fixed rate interest included in the RMT note payable on the Consolidated Statement of Cash Flows represents the quarterly noncash reclassification of the deferred fixed rate interest from an accrued liability to the RMT note payable. The amortization of deferred set-up fee and fixed rate interest on the RMT note payable relates to amounts recognized in the income statement as interest expense, which were not payable until maturity. The RMT note payable was repaid in May 2003 (see Note 10).

FINANCING ACTIVITIES

For a discussion of borrowings and repayments in 2003, see Note 10 of Notes to Consolidated Financial Statements.

Dividends paid on common stock are currently $.01 per common share on a quarterly basis and total $15.5 million for the nine months ended September 30, 2003. Additionally, one of the covenants under the indenture for the new $800 million senior unsecured notes due 2010 currently limits the quarterly common stock dividends paid by Williams to not more than $.02 per common share. This restriction may be removed in the future as Williams' financial condition improves and certain requirements in the covenants are met (see Note 10). Williams also paid $32.6 million in accrued dividends on the 9 7/8 percent cumulative-convertible preferred shares that were redeemed in June 2003.

On October 23, 2003, Williams announced that its PIGAP high-pressure gas compression project in Venezuela had obtained $230 million in non-recourse financing. Williams owns a 70 percent interest in the project. Proceeds from the loan will be used to repay notes due to Williams and the other owner for a portion of the initial funding of construction-related costs. Upon the execution of the loan, the project also made additional cash distributions to the owners based on their respective ownership interests. Williams expects to receive approximately $185 million, less applicable taxes, in total cash proceeds.

INVESTING ACTIVITIES

For 2003, net cash proceeds from asset dispositions, sales of businesses and disposition of investments include the following:

- $799 million related to the sale of Texas Gas Transmission Corporation
- $464 million related to certain natural gas exploration and production properties in Kansas, Colorado, New Mexico and Utah
- $452 million related to the sale of the Midsouth refinery
- $431 million (net of cash held by Williams Energy Partners) related to the sale of Williams' general partnership interest and limited partner investment in Williams Energy Partners
- $192 million related to the sale of certain natural gas liquids assets in Redwater, Alberta
- $188 million related to the sale of the Williams travel centers
- $59 million related to the sale of Williams' equity interest in Williams Bio-Energy L.L.C.
- $40 million related to the sale of the Worthington facility
- $36 million related to the sale of a natural gas processing plant in western Canada
- $29 million related to the sale of Williams investment in the Rio Grand Pipeline
- $29 million related to the sale of Williams investment in West Texas LPG Pipeline Limited Partnership
- $27 million related to the sale of Williams investment in American Soda, LLP

COMMITMENTS

The table below summarizes the maturity dates of the more significant contractual obligations and commitments by period.

	OCT. 1- DEC. 31, 2003	2004	2005	2006	2007	THEREAFTER	TOTAL
	(MILLIONS)						
Notes payable	$ 3	$ 4	$ --	$ --	$ --	$ --	$ 7
Long-term debt, including current portion	194	1,675	1,345(1)	959	905	7,826	12,904
Operating leases	21	35	24	12	10	21	123
Fuel conversion and other service contracts (2)	80	391	395	400	404	5,064	6,734
Total	$ 298	$ 2,105	$ 1,764	$ 1,371	$ 1,319	$ 12,911	$ 19,768

(1) Includes $1.1 billion of 6.5 percent notes, payable 2007 subject to remarketing in 2004 (FELINE PACS). If the remarketing is unsuccessful in 2004 and a second remarketing in February 2005 is unsuccessful as defined in the offering document of the FELINE PACS, then Williams could exercise its right to foreclose on the notes in order to satisfy the obligation of the holders of the equity forward contracts requiring the holder to purchase Williams common stock.

(2) Power has entered into certain contracts giving Williams the right to receive fuel conversion services as well as certain other services associated with electric generation facilities that are either currently in operation or are to be constructed at various locations throughout the continental United States.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

INTEREST RATE RISK

Williams' interest rate risk exposure associated with the debt portfolio was impacted by debt issuances in the first three quarters of 2003 and debt payments in each of the first three quarters. During 2003, Williams has repaid the RMT note payable (see Note 10), $224 million on the variable rate debt of Snow Goose LLC, $531.2 million of variable rate debt due in 2003 and 2004, $139.8 million of capitalized lease obligations, and $78.5 million of variable rate debt due in 2006. In the third quarter of 2003, Williams' Board of Directors authorized the Company to retire or otherwise prepay up to $1.8 billion of debt, including $1.4 billion designated for the Company's 9.25% notes due March 15, 2004. On October 8, 2003, the Company initiated a cash tender offer for any and all of Williams $1.4 billion senior unsecured 9.25 percent notes and cash tender offers and consent solicitations for approximately $241 million of additional outstanding notes and debentures. As of October 31, 2003, approximately $720 million of the 9.25 percent notes had been accepted for purchase. Additionally, Williams received tenders of notes and deliveries of related consents from holders of approximately $230 million of the other notes and debentures. The tender offers are scheduled to expire on November 6, 2003. During 2003, Williams, or its subsidiaries, issued the following debt:

- March 2003-Northwest Pipeline Corporation, a subsidiary of Williams, through a private debt placement, issued $175 million of 8.125 percent notes payable in 2010

- May 2003-Williams issued $300 million of 5.5 percent junior subordinated convertible debentures, due in 2033

- May 2003-Williams RMT Production Company issued a $500 million secured, subsidiary-level loan, due in 2007, at a floating interest rate of 3.75 percent over the six-month London InterBank Offered Rate

- June 2003-Williams issued $800 million of 8.625 percent senior unsecured notes due in 2010 under the company's $3 billion shelf registration statement

COMMODITY PRICE RISK

Power and Midstream are exposed to the impact of market fluctuations in the price of natural gas, electricity, crude oil, refined products, and natural gas liquids as a result of managing risk associated with the Company's owned energy-related assets and long-term energy-related contracts as well as its proprietary trading activities. Power and Midstream manage the risks associated with these market fluctuations using various derivatives for both trading and non-trading purposes. Certain of these derivative contracts are designated as cash flow hedges under SFAS No. 133 and others are accounted for under the mark-to-market method of accounting. Derivative contracts are subject to changes in energy commodity market prices, volatility and correlation of those commodity prices, the portfolio position of the contracts, the liquidity of the market in which the contract is transacted and changes in interest rates. The risk in the trading and non-trading portfolios is measured utilizing a value-at-risk methodology to estimate the potential one-day loss from adverse changes in the fair value of the portfolios. Value at risk requires a number of key assumptions and is not necessarily representative of actual losses in fair value that could be incurred from the portfolios. The value-at-risk model assumes that, as a result of changes in commodity prices, there is a 95 percent probability that the one-day loss in fair value of the portfolios will not exceed the value at risk. The value-at-risk model uses historical simulations to estimate hypothetical movements in future market prices assuming normal market conditions based upon historical market prices. Value at risk does not consider that changing the portfolio in response to market conditions could affect market prices and could take longer to execute than the one-day holding period assumed in the value-at-risk model. While a one-day holding period has historically been the industry standard, a longer holding period could more accurately represent the true market risk in an environment where market illiquidity and credit and liquidity constraints of the company may result in further inability to mitigate risk in a timely manner in response to changes in market conditions. Commodity contracts designated as a normal purchase or sale pursuant to SFAS No. 133 and non-derivative energy contracts have been excluded from the estimation of value at risk.

Trading

The trading portfolio consists of derivative contracts held to provide price risk management services to third-party customers based on a contract by contract assessment. These contracts are accounted for using the mark-to-market accounting method. At September 30, 2003 and December 31, 2002, the value at risk for the derivative contracts considered to be held for trading purposes was $13.3 million and $50.2 million, respectively. The adoption of EITF 02-3 resulted in non-derivative energy contracts no longer being accounted for and reported at fair value; therefore, such contracts have not been included in the September 30, 2003 trading value at risk. For the disclosure in the Form 10-Q for March 31, 2003, Power and Midstream considered all derivatives other than those designated as cash flow hedges under SFAS No. 133 to be trading. As previously noted, consistent with Williams' continued evaluation of its future involvement in the merchant power and generation business, beginning in the second quarter of 2003 trading contracts were reevaluated to include only those entered into to provide risk management services to third party customers and not those contracts that hedge or that could reasonably be considered a possible hedge of the market risk of Power and Midstream's own long-term structured portfolios.

Non-trading

The non-trading portfolio consists of derivative contracts that hedge or that could reasonably be considered a possible hedge of changes in energy commodity prices within Exploration & Production, the non-trading operations of Midstream and the non-trading operations of Power. Exploration & Production is exposed to commodity price risk associated with the sales price of the natural gas and crude oil it produces. Midstream is exposed to commodity price risk related to natural gas purchases, natural gas liquids purchases and sales, and electricity costs. Power is exposed to commodity price risk related to electricity purchased and sold and natural gas purchased for the production of electricity. At September 30, 2003, the non-trading portfolio consists of derivative contracts designated as cash flow hedges under SFAS No. 133 and non-trading derivative contracts accounted for under the mark-to-market method of accounting. The value-at-risk model did not consider the underlying commodity positions to which the cash flow hedges relate. Therefore, it is not representative of economic losses that could occur on a total non-trading portfolio basis that includes the underlying commodity positions. At September 30, 2003 and December 31, 2002, the value at risk for the non-trading derivative commodity instruments was $19.3 million and $45 million, respectively.

ITEM 4. CONTROLS AND PROCEDURES

An evaluation of the effectiveness of the design and operation of Williams' disclosure controls and procedures (as defined in Rule 13a-15(e) and 15(d) - (e) of the Securities Exchange Act) (Disclosure Controls) was performed as of the end of the period covered by this report. This evaluation was performed under the supervision and with the participation of Williams' management, including Williams' Chief Executive Officer and Chief Financial Officer. Based upon that evaluation, Williams' Chief Executive Officer and Chief Financial Officer concluded that, subject to the limitations noted below, these Disclosure Controls are effective.

Williams' management, including its Chief Executive Officer and Chief Financial Officer, does not expect that Williams' Disclosure Controls or its internal controls over financial reporting (Internal Controls) will prevent all error and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within the company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Additionally, controls can be circumvented by the individual acts of some persons, by collusion of two or more people, or by management override of the control. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions, or the degree of compliance with the policies or procedures may deteriorate. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected. Williams monitors its Disclosure Controls and Internal Controls and makes modifications as necessary; Williams' intent in this regard is that the Disclosure Controls and the Internal Controls will be maintained as systems change and conditions warrant.

There has been no change in Williams' Internal Controls that occurred during the period covered by this report that has materially affected, or is reasonably likely to materially affect, Williams' Internal Controls.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

The information called for by this item is provided in Note 11 Contingent liabilities and commitments included in the Notes to Consolidated Financial Statements included under Part I, Item 1. Financial Statements of this report, which information is incorporated by reference into this item.

Item 2. Changes in Securities and Use of Proceeds

The terms of the $800 million 8.625 percent senior unsecured notes due 2010 issued on June 10, 2003 limit the payment of quarterly dividends to no greater than $.02 per common share. This restriction may be lifted if certain conditions, including Williams attaining an investment grade rating from both Moody's Investors Service and Standard and Poor's, are met.

Item 6. Exhibits and Reports on Form 8-K

(a) The exhibits listed below are filed as part of this report:

Exhibit 12-- Computation of Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividend Requirements.

Exhibit 31.1-- Certification of Chief Executive Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 31.2-- Certification of Chief Financial Officer pursuant to Rules 13a-14(a) and 15d-14(a) promulgated under the Securities Exchange Act of 1934, as amended, and Item 601(b)(31) of Regulation S-K, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

Exhibit 32--Certification of Chief Executive Officer and Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(b) During third-quarter 2003, Williams filed a Form 8-K on the following dates reporting events under the specified items: July 1, 2003 Items 5 and 7; July 18, 2003 Item 9; July 24, 2003 Items 5 and 7; August 5, 2003 Items 5, 7 and 9; August 12, 2003 Item 7, 9 and 12; September 12, 2003 Items 5, 7 and 9.

SIGNATURE

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

THE WILLIAMS COMPANIES, INC.

(Registrant)

/s/ Gary R. Belitz

Gary R. Belitz
Controller
(Duly Authorized Officer and
Principal Accounting Officer)

November 6, 2003

EXHIBIT 12

The Williams Companies, Inc.
Computation of Ratio of Earnings to Combined Fixed Charges
and Preferred Stock Dividend Requirements
(Dollars in millions)

	Nine months ended September 30, 2003
Earnings:	
Income from continuing operations before income taxes and cumulative effect of change in accounting principles	$ 238.5
Add:	
Interest expense - net	1,000.5
Rental expense representative of interest factor	19.2
Minority interest in income of consolidated subsidiaries	15.1
Interest expense - net - 50% owned companies	3.7
Equity losses in less than 50% owned companies	5.5
Other	(2.6)
Total earnings as adjusted plus fixed charges	$ 1,279.9
Fixed charges and preferred stock dividend requirements:	
Interest expense - net	$ 1,000.5
Capitalized interest	34.6
Rental expense representative of interest factor	19.2
Pre-tax effect of preferred stock dividend requirements of the	

Company 47.8
Interest accrued - 50% owned companies 3.7

Combined fixed charges and preferred stock dividend requirements $ 1,105.8
==============
Ratio of earnings to combined fixed charges and preferred stock dividend requirements 1.16
==============

EXHIBIT 31.1

SECTION 302 CERTIFICATION

I, Steven J. Malcolm, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Williams Companies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)), for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the period covered by the report that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 6, 2003

By: /s/ Steven J. Malcolm

President and Chief Executive Officer
(Principal Executive Officer)

EXHIBIT 31.2

SECTION 302 CERTIFICATION

I, Donald R. Chappel, certify that:

1. I have reviewed this quarterly report on Form 10-Q of The Williams Companies, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)), for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    c) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the period covered by the report that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: November 6, 2003

By: /s/ Donald R. Chappel

Chief Financial Officer
(Principal Financial Officer)

EXHIBIT 32

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of The Williams Companies, Inc. (the "Company") on Form 10-Q for the period ending September 30, 2003 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), each of the undersigned hereby certifies, in his capacity as an officer of the Company, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Steven J. Malcolm
- -----------------------
Steven J. Malcolm
Chief Executive Officer
November 6, 2003

/s/ Donald R. Chappel
- -----------------------
Donald R. Chappel
Chief Financial Officer
November 6, 2003

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report and shall not be considered filed as part of the Report.